



COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY

PIEDMONT REGIONAL OFFICE

4949-A Cox Road, Glen Allen, Virginia 23060

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Preston Bryant
Secretary of Natural Resources

David K. Paylor
Director

March 27, 2009

Mr. Robert L. Greene, P.E.
Plant Manager
Hopewell Cogeneration Facility
1114 Hercules Road
Hopewell, VA 23860

Location: City of Hopewell
Registration No.: 50967

Dear Mr. Greene:

Attached is a renewal Title V permit to operate your facility pursuant to 9 VAC 5 Chapter 80 of the Virginia Regulations for the Control and Abatement of Air Pollution.

This permit contains legally enforceable conditions. Failure to comply may result in a Notice of Violation and civil penalty. Please read all conditions carefully.

This approval to operate does not relieve Hopewell Cogeneration Limited Partnership of the responsibility to comply with all other local, state, and federal permit regulations.

Issuance of this permit is a case decision. The Regulations, at 9 VAC 5-170-200, provide that you may request a formal hearing from this case decision by filing a petition with the Board within 30 days after this permit is mailed or delivered to you. Please consult that and other relevant provisions for additional requirements for such requests.

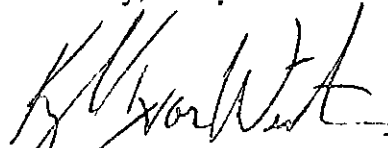
Additionally, as provided by Rule 2A:2 of the Supreme Court of Virginia, you have 30 days from the date you actually received this permit or the date on which it was mailed to you, whichever occurred first, within which to initiate an appeal to court by filing a Notice of Appeal with:

Mr. David K. Paylor, Director
Department of Environmental Quality
P. O. Box 1105
Richmond, VA 23218

In the event that you receive this permit by mail, three days are added to the period in which to file an appeal. Please refer to Part Two A of the Rules of the Supreme Court of Virginia for additional information including filing dates and the required content of the Notice of Appeal.

If you have any questions concerning this permit, please contact the Piedmont Regional Office at (804) 527-5020.

Sincerely,

A handwritten signature in black ink, appearing to read 'Kyle I. Winter', is written over a horizontal line.

Kyle I. Winter, P.E.
Deputy Regional Director

KIW/mm/50967-5 Title V Permit Cover Letter.doc

Attachment: Permit
NSPS Subpart Db
NSPS Subpart GG
Attachment A- Clean Air Interstate Rule application
Statement of Basis

cc: Director, OAPP (electronic file submission)
Manager, Data Analysis (electronic file submission)
Chief, Air Enforcement Branch (3AP13), U.S. EPA, Region III
Manager/Inspector, Air Compliance



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Federal Operating Permit Article 1

This permit renewal is based upon the requirements of Title V of the Federal Clean Air Act and Chapter 80, Article 1, and Chapter 140 of the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution. Until such time as this permit is reopened and revised, modified, revoked, terminated or expires, the permittee is authorized to operate in accordance with the terms and conditions contained herein. This permit is issued under the authority of Title 10.1, Chapter 13, §10.1-1322 of the Air Pollution Control Law of Virginia. This permit is issued consistent with the Administrative Process Act, and 9 VAC 5-80-50 through 9 VAC 5-80-300, and 9 VAC 5-140-10 through 9 VAC 5-140-900 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution of the Commonwealth of Virginia.

Authorization to operate a Stationary Source of Air Pollution as described in this permit is hereby granted to:

Permittee Name:	Hopewell Cogeneration Limited Partnership
Facility Name:	Hopewell Cogeneration Facility
Facility Location:	1114 Hercules Road Hopewell, Virginia 23860

Registration Number:	50967
Permit Number:	PRO50967

This permit includes the following programs:

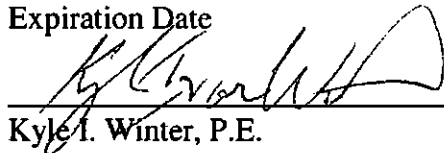
Federally Enforceable Requirements - Clean Air Act (Sections I through VIII)
Federally Enforceable Requirements - Clean Air Interstate Rule (Section IX)

March 27, 2009

Effective Date

March 26, 2014

Expiration Date



Kyle I. Winter, P.E.

Deputy Regional Director

MARCH 27 2009

Signature Date

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I. Facility Information

Permittee

Hopewell Cogeneration Limited Partnership.
Hopewell Cogeneration Facility
1114 Hercules Road
Hopewell, Va. 23860

Responsible Official

Mr. Robert L. Greene, P.E.
Plant Manager

Facility

Hopewell Cogeneration Facility
1114 Hercules Road
Hopewell, Va. 23860

Contact Person

Harry C. Barnes, Jr.
Environmental Representative
(804) 458-0700 ext. 203

County-Plant Identification Number: 51-670-0058

ORIS Code and/or EIA Facility ID (for non-EGU units): 10633

NATS Facility Identification Number: 010633

Facility Description: NAICS 221112 - Fossil Fuel Electric Power Generation
SIC 4911- Electric Services

The Hopewell Cogeneration Facility, a 356.5 MW combined cycle cogeneration facility, is an independent power producer. The facility has three ABB type 11 N combustion turbines, each rated at 1,143.6 MMBtu/hr on natural gas and 1,091.1 MMBtu/hr on distillate oil, and three unfired Nooter Eriksen heat recovery steam generators (HRSGs), each rated at 360,000 pounds/hour. The facility has one ABB 120,000 kW steam turbine, and two auxiliary Babcock and Wilcox boilers, each rated at 229.0 MMBtu/hr on natural gas and 220.0 MMBtu/hr on distillate oil. The facility has two Caterpillar 1,500 kW diesel generators and three 1.250 million gallon distillate oil tanks.

II. Emission Units

Equipment to be operated consists of:

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Fuel Burning Equipment							
CT1	CT1-001	Combustion Turbine Type 11 N ABB Model ABHHM300555 (07/88)	1143.6 MMBtu/hr- nat. gas input; 1091.1 MMBtu/hr- No. 2 fuel oil input	I-99 Steam Injection	CT1	NOx	December 18, 2008
CT2	CT2-002	Combustion Turbine Type 11 N ABB Model ABHHM300556 (07/88)	1143.6 MMBtu/hr- nat. gas input; 1091.1 MMBtu/hr- No. 2 fuel oil input	I-99 Steam Injection	CT1	NOx	December 18, 2008
CT3	CT3-003	Combustion Turbine Type 11 N ABB Model ABHHM300564 (07/88)	1143.6 MMBtu/hr- nat. gas input; 1091.1 MMBtu/hr- No. 2 fuel oil input	I-99 Steam Injection	CT1	NOx	December 18, 2008
AB1	AB1-004	Auxiliary Boiler Babcock & Wilcox (07/88)	229.0 MMBtu/hr- nat. gas input; 220.0 MMBtu/hr- No. 2 fuel oil input	I-99 Low NOx burner and I-99 Flue Gas Recirculation	AB1	NOx	December 18, 2008
AB2	AB2-005	Auxiliary Boiler Babcock & Wilcox (07/88)	229.0 MMBtu/hr- nat. gas input; 220.0 MMBtu/hr- No. 2 fuel oil input	I-99 Low NOx burner and I-99 Flue Gas Recirculation	AB1	NOx	December 18, 2008
G1	G1-06	Emergency Generator Caterpillar (07/88)	5.1 MMBtu/hr – No. 2 fuel oil input (1,500 kW)	-	-	-	December 18, 2008
G2	G1-06	Emergency Generator Caterpillar (07/88)	5.1 MMBtu/hr – No. 2 fuel oil input (1,500 kW)	-	-	-	December 18, 2008

Emission Unit ID	Stack ID	Emission Unit Description	Size/Rated Capacity*	Pollution Control Device (PCD) Description	PCD ID	Pollutant Controlled	Applicable Permit Date
Fuel Storage Tanks							
I3	N/A	Fuel Storage Tank	1,250,000 gallons, vertical fixed roof (07/88)	-	-	-	June 6, 1990, December 18, 2008

*The Size/Rated capacity is provided for informational purposes only, and is not an applicable requirement.

III. Fuel Burning Equipment Requirements – (Emission Unit ID Nos. CT1, CT2, CT3, AB1, AB2, G1, and G2)

A. Limitations

1. Nitrogen oxide emissions from the combustion turbines (Reference Nos. CT1, CT2, and CT3) shall be controlled by the use of steam injection. The steam injection system shall be provided with adequate access for inspection and shall be in operation when the combustion turbines are operating.
(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 3 of 12/18/08 PSD Permit)
2. Nitrogen oxide emissions from the auxiliary boilers (Reference Nos. AB1 and AB2) shall be controlled through boiler design employing multi-stage low NO_x burners.
(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 4 of 12/18/08 PSD Permit)
3. The approved fuels for the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) are distillate oil and natural gas. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 13 of 12/18/08 PSD Permit)
4. Sulfur dioxide (SO₂) emissions from the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) shall be controlled by limiting the sulfur content of the distillate oil to 0.2 percent by weight.
(9 VAC 5-50-280, 9 VAC 5-80-110, 9 VAC 5-50-410, and Condition 5 of 12/18/08 PSD Permit)
5. The distillate oil shall meet the specifications below:

DISTILLATE OIL which meets the ASTM D396 specification for numbers 1 or 2 fuel oil:
Maximum sulfur content per shipment: 0.2 %
(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 17 of 12/18/08 PSD Permit)
6. Each combustion turbine (Reference Nos. CT1, CT2, and CT3) shall consume no more than 61.19×10^6 gallons of distillate oil or 8.99×10^9 cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 14 of 12/18/08 PSD Permit)
7. Each auxiliary boiler (Reference Nos. AB1 and AB2) shall consume no more than 13.77×10^6 gallons of distillate oil or 2.01×10^9 cubic feet of natural gas per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for

the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

(9 VAC 5-50-280, 9 VAC 5-80-110 and Condition 15 of 12/18/08 PSD Permit)

8. The emergency generators (Reference Nos. G1 and G2) shall not be operated when any of the three combustion turbines (Reference Nos. CT1, CT2, and CT3) is on line. The generator(s) shall be used only to start-up one single turbine after which the generator(s) shall be taken off-line. The emergency generators shall consume no more than 55,800 gallons of distillate oil combined per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

(9 VAC 5-50-280, 9 VAC 5-80-110 and Condition 16 of 12/18/08 PSD Permit)

9. Emissions from the operation of each combustion turbine (Reference Nos. CT1, CT2, and CT3) shall not exceed the limits specified below:

For Natural Gas Firing:

Particulate Matter (PM)	4.0×10^{-3} lbs/MMBtu	4.57 lbs/hr	18.0 tons/yr
Sulfur Dioxide	5.4×10^{-4} lbs/MMBtu	0.62 lbs/hr	2.4 tons/yr
Nitrogen Oxides	42 ppm _{dv} @ 15% O ₂	176.9 lbs/hr	675.6 tons/yr
Carbon Monoxide		25.8 lbs/hr	110.4 tons/yr
Volatile Organic Compounds		0.72 lbs/hr	3.1 tons/yr

For Distillate Oil Firing:

Particulate Matter (PM)	0.039 lbs/MMBtu	28.0 lbs/hr	122.6 tons/yr
Sulfur Dioxide	0.21 lbs/MMBtu	225.0 lbs/hr	896.8 tons/yr
Nitrogen Oxides	65 ppm _{dv} @ 15% O ₂	275.7 lbs/hr	1036.9 tons/yr
Carbon Monoxide		26.0 lbs/hr	112.0 tons/yr
Volatile Organic Compounds		7.0 lbs/hr	29.1 tons/yr

Lead 0.0057 lbs/hr 0.0235 tons/yr

(9 VAC 5-50-280, 9 VAC 5-50-410, 9 VAC 5-80-110, 40 CFR 60 Subpart GG, and Condition 21 of 12/18/08 PSD Permit)

10. Emissions from the operation of each auxiliary boiler (Reference Nos. AB1 and AB2) shall not exceed the limits specified below:

For Natural Gas Firing:

Particulate Matter (PM)	0.1 lbs/MMBtu	22.9 lbs/hr	100.3 tons/yr
Sulfur Dioxide	6.0×10^{-4} lbs/MMBtu	0.14 lbs/hr	0.6 tons/yr
Nitrogen Oxides	0.1 lbs/MMBtu	22.9 lbs/hr	100.3 tons/yr
Carbon Monoxide		19.9 lbs/hr	87.3 tons/yr
Volatile Organic Compounds		1.15 lbs/hr	5.0 tons/yr

For Distillate Oil Firing:

Particulate Matter (PM)	0.1 lbs/MMBtu	22.0 lbs/hr	96.4 tons/yr
Sulfur Dioxide	0.2 lbs/MMBtu	44.0 lbs/hr	192.7 tons/yr
Nitrogen Oxides	0.1 lbs/MMBtu	22.0 lbs/hr	96.4 tons/yr
Carbon Monoxide		19.1 lbs/hr	83.8 tons/yr
Volatile Organic Compounds		1.1 lbs/hr	4.8 tons/yr
Lead		0.0012 lbs/hr	0.0053 tons/yr

(9 VAC 5-50-280, 9 VAC 5-50-410, 9 VAC 5-80-110, 40 CFR 60 Subpart Db, and Condition 22 of 12/18/08 PSD Permit)

11. Emissions from the operation of both emergency generators combined (Reference Nos. G1 and G2) shall not exceed the limits specified below:

For Distillate Oil Firing:

Sulfur Dioxide	2.8 lbs/hr	0.8 tons/yr
Nitrogen Oxides	45.1 lbs/hr	12.5 tons/yr
Carbon Monoxide	12.0 lbs/hr	3.3 tons/yr

(9 VAC 5-50-280, 9 VAC 5-80-110, and Condition 23 of 12/18/08 PSD Permit)

12. Non-criteria pollutant emissions from the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) shall be controlled by not exceeding the fuel usage limitations specified in Part III. A. Conditions 6 and 7 of this permit.

(9 VAC 5-60-320, 9 VAC 5-80-110, and Condition 6 of 12/18/08 PSD Permit)

13. The facility shall operate in compliance with 9 VAC 5-60 Article 4- *Toxic Pollutants from Existing Sources* and 9 VAC 5-60 Article 5- *Toxic Pollutants from New and Modified Sources*. No changes in the facility that alter emissions of any non-criteria pollutant or cause the emission of additional toxic pollutants shall be made without the prior written approval of the Board.

(9 VAC 5-60-220, 5-60-320, 9 VAC 5-80-110, and Condition 35 of 12/18/08 PSD Permit)

14. Except where this permit is more restrictive than the applicable requirement, the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) shall be operated in compliance with the requirements of 40 CFR 60, Subpart GG *Standards of Performance for Stationary Gas Turbines* and 40 CFR 60, Subpart Db *Standards of Performance for Industrial – Commercial – Institutional Steam Generating Units*.

(9 VAC 5-50-410, 9 VAC 5-80-110, and Condition 20 of 12/18/08 PSD Permit)

15. The permittee shall meet the nitrogen oxide standards as specified in 40 CFR 60.44b at all times including periods of startup, shutdown, and malfunction.

(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.44b(h))

16. Except as provided by 40 CFR 60.44b(j), the permittee shall show compliance with the emission limits of 40 CFR 60.44b based on a 30-day rolling average.

(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.44b(i))

17. The permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$\text{STD} = 0.0075 * [(14.4) / Y] + F$$

where:

STD = allowable NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis);
 Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour; and
 F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of 40 CFR 60 Subpart GG 60.332.

(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.332(a)(1))

18. The permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.333(a))

19. For combustion turbines supplied distillate oil from a bulk storage tank, the permittee shall determine the values of sulfur content and nitrogen content of the fuel oil after each addition of fuel oil to the bulk storage tank from any other source.

(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.334(i)(1))

20. The permittee shall determine compliance with the nitrogen oxides standards in 40 CFR 60.332 as follows:

For each run of the performance test, the mean nitrogen oxides emission concentration shall be computed using the following equation:

$$\text{NO}_x = (\text{NO}_{x0}) * (\text{P}_r / \text{P}_0)^{0.5} * (e^{[19 * (\text{H}_0 - 0.00633)]}) * (288 / \text{T}_a)^{1.53}$$

where:

NO_x = emission concentration of NO_x at 15 percent oxygen and ISO standard ambient conditions, ppm by volume, dry basis;
 NO_{x0} = mean observed NO_x concentration, ppm by volume, dry basis, at 15 percent oxygen;
 P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg;
 P₀ = observed combustor inlet absolute pressure at test, mm Hg;
 H₀ = observed humidity of ambient air, g H₂O / g air;
 e = transcendental constant, 2.718; and
 T_a = ambient temperature, K.

(9 VAC 5-50-410, 9 VAC 5-80-110, Condition 24 of 12/18/08 PSD Permit, and 40 CFR 60 Subpart GG 60.335(b)(1))

21. If the permittee elects to install and certify a NO_x CEMS under 40 CFR 60.334(e), then the performance test to determine compliance with the nitrogen oxides standards in 40 CFR 60.332 may be done in the following alternative manner:
- a. Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.
 - b. Use the test data both to demonstrate compliance with the applicable NO_x emission limit under 40 CFR 60.332 and to provide the required reference method data for the RATA of the CEMS described under 40 CFR 60.334(b).
 - c. The requirement to test at three additional load levels is waived.
(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.335(b)(7))
22. The permittee shall determine compliance with the sulfur content standard as specified in 40 CFR 60.333(b) as follows: ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00, or D1552-01 shall be used to determine the sulfur content of liquid fuels and ASTM D1072-80, 90; D3246-81, 92, 96; D4468-85; or D6667-01 shall be used for the sulfur content of gaseous fuels (incorporated by reference, see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some gaseous fuels. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of EPA Region III.
(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.335(b)(10))
23. To meet the requirements of 40 CFR 60.332(a), the permittee shall use the analytical methods and procedures as specified in 40 CFR 60.335(b)(9) to measure nitrogen content if an emission allowance is claimed for fuel bound nitrogen and shall determine compliance with sulfur content standard as described in 40 CFR 60.335(b)(10) and Section III, A, Condition 21 of this permit for the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart GG 60.335(b))
24. For the combustion turbines (Reference Nos. CT1, CT2, and CT3), the terms "start-up" and "shutdown" shall be defined as follows:
Start-up: The period, for each unit start command, from the beginning of "warm up" control mode or from the point a restart is issued for a running unit in shutdown mode and continuing to the end of the first hour of water injection logging for NO_x control.
Shutdown: The period, for each unit stop command, from when the control "shutdown" mode begins and continuing until no fuel is being combusted or until a restart command is received, whichever occurs first.
(9 VAC 5-80-110)

B. Monitoring

1. Continuous Emission Monitoring Systems, meeting the design specifications of 40 CFR 60, Appendix B, shall be installed to measure and record the emissions of nitrogen oxides (NO_x) from the combustion turbines (Reference Nos. CT1, CT2, and CT3) as parts per million by volume, dry basis, corrected to fifteen percent oxygen. The CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 60.13, 40 CFR 60 Subpart GG, and 40 CFR 60 Appendices B and F. Data shall be reduced to hourly averages as specified in 40 CFR 60.13(h). The SPAN VALUE for the NO_x monitor shall be 120 parts per million in accordance with 40 CFR Part 75.
(9 VAC 5-50-40, 9 VAC 5-50-410, 9 VAC 5-80-110, 9 VAC 5-140-700, and Condition 7 of 12/18/08 PSD Permit)
2. Continuous Emission Monitoring Systems, meeting the design specifications of 40 CFR 60, Appendix B, shall be installed to measure and record the emissions of nitrogen oxides (NO_x) from the auxiliary boilers (Reference Nos. AB1 and AB2) as pounds per million BTU heat input. The CEMS shall be installed, calibrated, maintained, audited and operated in accordance with the requirements of 40 CFR 60.13, 40 CFR 60 Subpart Db, and 40 CFR 60 Appendices B and F. Data shall be reduced to hourly averages as specified in 40 CFR 60.13(h). The SPAN VALUE for the NO_x monitor shall be 300 parts per million in accordance with 40 CFR Part 60, Subpart Db.
(9 VAC 5-50-40, 9 VAC 5-50-410, 9 VAC 5-80-110, and Condition 8 of 12/18/08 PSD Permit)
3. Continuous Opacity Monitoring Systems, meeting the design specifications of 40 CFR 60, Appendix B, shall be installed to measure and record the opacity of emissions from the auxiliary boilers (Reference Nos. AB1 and AB2). The COMS shall be installed, calibrated, maintained and operated in accordance with the requirements of 40 CFR 60.13, 40 CFR 60 Subpart Db and 40 CFR 60 Appendix B. Data shall be reduced to six minute averages.
(9 VAC 5-50-40, 9 VAC 5-50-410, 9 VAC 5-80-110, and Condition 9 of 12/18/08 PSD Permit)
4. A continuous opacity monitoring system may be used to satisfy the visible emission evaluation requirement in lieu of 40 CFR, Part 60, Appendix A, Method 9. The reported test data shall include averages of all six minute continuous periods within the test period and within the duration of any mass emission performance tests being conducted. It is the responsibility of the permittee to demonstrate that the monitoring system has met the requirements of the applicable performance evaluation, that the monitoring system has been properly maintained and operated, and that the resulting data has not been altered in any way. If monitoring system data indicates compliance

for a period during which Method 9 data indicates non-compliance, the Method 9 data shall be used to determine compliance with the visible emission limit.

(9 VAC 5-50-20, 9 VAC 5-80-110, and Condition 10 of 12/18/08 PSD Permit)

5. Performance evaluations of the continuous monitoring systems shall be conducted in accordance with 40 CFR Part 60, Appendix B and 40 CFR 75.20, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. Two copies of the performance evaluations report shall be submitted to the Piedmont Region within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30 day notification, prior to the demonstration of continuous monitoring system's performance, and subsequent notifications shall be submitted to the Piedmont Region.

(9 VAC 5-50-40, 9 VAC 5-50-410, 9 VAC 5-80-110, 9 VAC 5-140-700, and Condition 11 of 12/18/08 PSD Permit)

6. A CEMS/COMS quality control program which meets the requirements of 40 CFR 60.13 and Appendix B or F shall be implemented for all continuous monitoring systems.

(9 VAC 5-50-40, 9 VAC 5-50-410, 9 VAC 5-80-110, 9 VAC 5-140-700, and Condition 12 of 12/18/08 PSD Permit)

7. The permittee shall monitor the sulfur and nitrogen content of the fuel being fired in the combustion turbines (Reference Nos. CT1, CT2, and CT3) in accordance with 40 CFR 60.334(h).

(9 VAC 5-50-410, 9 VAC 5-80-110, and Condition 19 of 12/18/08 PSD Permit)

C. Recordkeeping

1. The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:
 - a. The name of the fuel supplier;
 - b. The date on which the distillate oil was received;
 - c. The quantity of distillate oil delivered in the shipment;
 - d. A statement that the distillate oil complies with the American Society for Testing and Materials specifications (ASTM D396) for numbers 1 or 2 fuel oil; and
 - e. The sulfur content of the distillate oil;

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition III. A. 5. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits.

(9 VAC 5-50-410, 9 VAC 5-80-110 and Condition 18 of 12/18/08 PSD Permit)

2. The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Piedmont Region. These records shall include, but are not limited to:
 - a. Continuous emissions monitoring system calibrations and calibration checks, percent operating time, and excess emissions.
 - b. Annual consumption of distillate oil and natural gas for each combustion turbine (Reference Nos. CT1, CT2, and CT3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
 - c. Annual consumption of distillate oil and natural gas for each auxiliary boiler (Reference Nos. AB1 and AB2), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
 - d. Annual consumption of distillate oil for both emergency generators combined (Reference Nos. G1 and G2), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
 - e. All fuel supplier certifications.
 - f. Scheduled and unscheduled maintenance, and operator training.
 - g. The operating status of the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) at the beginning and ending of each period that an emergency generator (Reference Nos. G1 and G2) is used. The amount of distillate oil used by the emergency generator during the event shall be included in the record.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.

(9 VAC 5-50-50, 9 VAC 5-50-410, 9 VAC 5-80-110, and Condition 25 of 12/18/08 PSD Permit)

3. At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to the combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2):
 - a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.
 - b. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.
 - c. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures, prior to their first operation of such equipment. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.

(9 VAC 5-80-110 and Condition 32 of 12/18/08 PSD Permit)

4. The permittee shall record and maintain records of the amounts of each fuel combusted in the auxiliary boilers (Reference Nos. AB1 and AB2) during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.
(9 VAC 5-50-50, 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.49b(d))
5. The permittee shall maintain records of opacity for the auxiliary boilers (Reference Nos. AB1 and AB2) subject to the opacity standard as specified in 40 CFR 60.43b.
(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.49b(f))
6. The permittee shall maintain all records required under 40 CFR 60 Subpart 60.49b for a period of 2 years following the date of such record.
(9 VAC 5-50-50, 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart 60.49b(o))

7. The permittee, subject to the provision of 9 VAC 5-50-40 A, shall maintain records of the occurrence and duration of any startup, shutdown or malfunction in the operation of the combustion turbines, auxiliary boilers, and emergency generators (Reference Nos. CT1, CT2, CT3, AB1, AB2, G1, and G2); any malfunction of the air pollution control equipment; or any period during which a continuous monitoring system or monitoring device is inoperative.
(9 VAC 5-50-50 B and 9 VAC 5-80-110)
8. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this chapter recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports and records.
(9 VAC 5-50-50 D and 9 VAC 5-80-110)
9. The permittee shall obtain and maintain at the affected facility fuel receipts from the fuel supplier which certify that the oil meets the definition of distillate oil as defined in 40 CFR 60.41b. For the purposes of 40 CFR 60.49, the oil need not meet the fuel nitrogen content specification in the definition of distillate oil. The permittee shall submit reports to the Director, Piedmont Region certifying that only very low sulfur oil meeting this definition was combusted in the affected facility during the reporting period.
(9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.49b(r))

D. Testing

1. The combustion turbines (Reference Nos. CT1, CT2, and CT3) and auxiliary boilers (Reference Nos. AB1 and AB2) shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility/equipment such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing a stack or duct that is free from cyclonic flow. Sampling ports shall be provided when requested and safe sampling platforms and access shall be provided.
(9 VAC 5-50-30, 9 VAC 5-80-110, and Condition 2 of 12/18/08 PSD Permit)
2. If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.
(9 VAC 5-80-110)

3. Once per permit term, stack emission tests shall be conducted for opacity from the combustion turbines (Reference Nos. CT1, CT2, and CT3) using 40 CFR Part 60, Appendix A, Method 9. Stack tests for new or modified sources shall be conducted and reported and data reduced as set forth in Sections 9 VAC 5-50-30 and 9 VAC 5-60-30 of State Regulations and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410, and 9 VAC 5-60-70. The details of the emission tests are to be arranged with the Director, Piedmont Region. (9 VAC 5-80-110)
4. Except as provided in 40 CFR 60.11(e)(3), the permittee, to which an opacity standard in this part applies, shall conduct opacity observations in accordance with 40 CFR 60.11(b), shall record the opacity of emissions, and shall report to the Director, Piedmont Region the opacity results along with the results of the initial performance test required by 40 CFR 60.8. The inability of the permittee to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.
(9 VAC 5-50-410, 9 VAC 5-80-110, 40 CFR 60 Subpart Db 60.49b(f), and 40 CFR 60 Subpart A 60.11(e)(2))

E. Reporting

1. The permittee shall furnish written notification to the Piedmont Region of:
 - a. The anticipated date of continuous monitoring system performance evaluations postmarked not less than 30 days prior to such date.
 - b. The intention to use continuous opacity monitoring system data results to demonstrate compliance with the applicable visible emission limit during a performance test in lieu of Reference Method 9 (reference 40 CFR Part 60, Appendix A), postmarked not less than 30 days prior to the date of the performance test.
 - c. The anticipated date of performance tests of the combustion turbines (Reference Nos. CT1, CT2, and CT3) or auxiliary boilers (Reference Nos. AB1 and AB2) postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items a. through c. above are to be sent to:

Associate Director
Office of Air Enforcement (3AP10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029
(9 VAC 5-50-50 and 9 VAC 5-80-1180)

2. The permittee shall submit fuel quality reports to the Director, Piedmont Regional Office within 30 days after the end of each calendar quarter. If no shipments of distillate oil were received during the calendar quarter, the quarterly report shall consist of the dates included in the calendar quarter and a statement that no oil was received during the calendar quarter. If distillate oil was received during the calendar quarter, the reports shall include:
 - a. The dates included in the calendar quarter;
 - b. A copy of all fuel supplier certifications for all shipments of distillate oil received during the calendar quarter or a quarterly summary from each fuel supplier that includes the information specified in Condition III. C. 1. for each shipment of distillate oil; and,
 - c. A signed statement from the owner or operator of the facility that the fuel supplier certifications or summaries of fuel supplier certifications represent all of the distillate oil burned or received at the facility.

(9 VAC 5-50-50 and 9 VAC 5-80-110)
3. If, for any reason, the permittee does not comply or will not be able to comply with the emission limitations or other conditions specified in this permit, the permittee shall provide in writing to the Director, Piedmont Region the following information as soon as possible but no later than five (5) days after such conditions become known to the permittee:
 - a. Description of non-compliance;
 - b. Cause of non-compliance;
 - c. Anticipated time the non-compliance is expected to continue or, if corrected, the actual duration of non-compliance;
 - d. Steps taken by the permittee to minimize or eliminate the non-compliance; and
 - e. Steps taken by the permittee to prevent recurrence of the non-compliance.

(9 VAC 5-50-50, 9 VAC 5-80-110, and Condition 28 of 12/18/08 PSD Permit)
4. For the auxiliary boilers (Reference Nos. AB1 and AB2), subject to the nitrogen oxide standards of 40 CFR 60.44b, the permittee shall maintain records of and report the following information for each steam generating unit operating day to the Director, Piedmont Region on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter:
 - a. Calendar date.

- b. The average hourly nitrogen oxides emission rates (expressed as NO₂) (ng/J or lb/million Btu heat input) measured or predicted.
 - c. The 30-day average nitrogen oxides emission rates (ng/J or lb/million Btu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days.
 - d. Identification of the steam generating unit operating days when the calculated 30-day average nitrogen oxides emission rates are in excess of the nitrogen oxides emissions standards under 40 CFR 60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken.
 - e. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.
 - f. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data.
 - g. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
 - h. Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.
 - i. Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specification 2 or 3.
 - j. Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.
- (9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.49b(g) and (i))
5. For the auxiliary boilers (Reference Nos. AB1 and AB2) subject to the sulfur dioxide standards under §60.42b, to the compliance and performance testing requirements of 40 CFR 60.45b, and to the reporting requirement of 40 CFR 60.49b(j), the permittee shall submit the following reports to the Director, Piedmont Region on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter:
- a. Calendar dates covered in the reporting period
 - b. Each 30-day average sulfur dioxide emission rate (ng/J or lb/million Btu heat input) measured during the reporting period, ending with the last 30-day

period; reasons for non-compliance with the emission standards; and a description of corrective actions taken.

- c. Each 30-day average percent reduction in sulfur dioxide emissions calculated during the reporting period, ending with the last 30-day period; reasons for non-compliance with the emission standards; and a description of corrective actions taken.
 - d. Identification of the steam generating unit operating days that coal or oil was combusted and for which sulfur dioxide or diluent (oxygen or carbon dioxide data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken.
 - e. Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.
 - f. Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.
 - g. Identification of times when hourly averages have been obtained based on manual sampling methods.
 - h. Identification of the times when the pollutant concentration exceeded full span of the CEMS.
 - i. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with 40 CFR 60 Appendix B, Performance Specifications 2 or 3.
 - j. Results of daily CEMS drift tests and quarterly accuracy assessments as required under 40 CFR 60 Appendix F, Procedure 1.
 - k. The annual capacity factor of each fired as specified in 40 CFR 60.49b(d). (9 VAC 5-50-50 and 9 VAC 5-50-410, 9 VAC 5-80-110, and 40 CFR 60 Subpart Db 60.49b(j) and (k))
6. The permittee shall furnish written reports to the Piedmont Region of excess emissions from any process monitored by a continuous monitoring system (COMS/CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of the calendar quarter. These reports shall include, but are not limited to the following information:

- a. The magnitude of excess emissions for sulfur dioxide, nitrogen dioxide, ice fog, and emergency fuel as required in 40 CFR 60.334(j), any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;
- b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;
- c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and
- d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report.

(9 VAC 5-50-50, 9 VAC 5-50-410, and 9 VAC 5-80-110)

IV. Process Equipment Requirements – (emission unit ID No. I3)

A. Limitations

1. Emissions from the operation of the 1.25 million gallon distillate oil storage tank (reference No. I3) shall not exceed the limitations specified below. Annual emissions shall be calculated monthly as the sum of the previous consecutive 12 month period:

Volatile Organic Compounds	0.2 lbs/hr	1.0 tons/yr
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(9 VAC 5-50-260, 9 VAC 5-80-110, and Condition 3 of 6/6/90 NSR Permit)

2. The yearly throughput of distillate oil stored in the 1.25 million gallon distillate oil storage tank (reference No. I3) shall not exceed 84×10^6 gallons, calculated monthly as the sum of the previous consecutive 12 month period..

(9 VAC 5-170-160, 9 VAC 5-80-110, and Condition 4 of 6/6/90 NSR Permit)

3. The facility shall operate in compliance with 9 VAC 5-60 Article 4- *Toxic Pollutants from Existing Sources* and 9 VAC 5-60 Article 5- *Toxic Pollutants from New and Modified Sources*. No changes in the facility that alter emissions of any non-criteria pollutant or cause the emission of additional toxic pollutants shall be made without the prior written approval of the Board.

(9 VAC 5-60-220, 5-60-320, 9 VAC 5-80-110, and Condition 5 of 6/6/90 NSR Permit)

4. The approved fuel for storage is distillate oil. A change in the fuel stored may require a permit to modify and operate. The distillate oil shall meet the ASTM D396-78 specifications for numbers 1 or 2 fuel oil.

(9 VAC 5-170-160, 9 VAC 5-80-110, and Condition 6 of 6/6/90 NSR Permit)

5. Volatile organic compound emissions from 1.25 million gallon distillate oil storage tanks (reference No. I3) shall be controlled by a fixed roof design with pressure vacuum valve.

(9 VAC 5-80-110)

B. Recordkeeping

1. The permittee shall maintain records of all emission data and operating parameters necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Piedmont Regional Office. These records shall include, but are not limited to:

- a. Annual throughput of distillate oil stored in the 1.25 million gallon distillate oil storage tank (reference No. I3), calculated monthly as the sum of each consecutive twelve (12) month period.
- b. Records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel. Such records shall be readily accessible.

These records shall be available on site for inspection by the DEQ and shall be current for the most recent five (5) years.

(9 VAC 5-50-50, 9 VAC 5-80-110, and Condition 8 of 06/06/90 NSR Permit)

V. Facility Wide Conditions

A. General Conditions

1. Regardless of any other provision of this section, any facility which is subject to the provisions of 9 VAC 5-50-170 through 9 VAC 5-50-230 shall shut down immediately upon request of the board if its emissions increase in any amount because of a bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment; and such facility shall not return to operation until it and the associated air pollution control equipment are able to operate in a proper manner.
(9 VAC 5-20-180 F 3)
2. The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I and 9 VAC 5-80-1180)
3. In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Piedmont Region of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240)
4. The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-80-1180)
5. The conditions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of that provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
(9 VAC 5-170-160)

6. The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:
 - a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;
 - b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;
 - c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and
 - d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130 and 9 VAC 5-80-1180)

7. At all times the disposal of volatile organic compounds shall be accomplished by taking measures, to the extent practicable, consistent with air pollution control practices for minimizing emissions. Volatile organic compounds shall not be intentionally spilled, discarded in sewers which are not connected to a treatment plant, or stored in open containers or handled in any manner that would result in evaporation beyond that consistent with air pollution control practices for minimizing emissions.
(9 VAC 5-50-20 F)
8. During the construction, modification or operation phase of a stationary source or any other building, structure, facility or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne.
(9 VAC 5-50-90 and 9 VAC 5-50-300)
9. The owner shall use the best available control technology as approved by the board for the control of odorous emissions.
(9 VAC 5-50-140 A and 9 VAC 5-50-310)
10. No owner or other person shall cause or permit to be discharged into the atmosphere from any affected facility any odorous emissions in excess of that resultant from

using best available control technology, as reflected in any condition that may be placed upon the permit approval for the facility.

(9 VAC 5-50-140 B)

11. Unless specified otherwise in this part, on or after the date on which the performance test required to be conducted is completed, no owner or other person shall cause or permit to be discharge into the atmosphere from any affected facility any visible emissions which exhibit greater than 20 percent opacity, except for one six-minute period in any one hour of not more than 30 percent opacity. Failure to meet the requirements of this section because of the presence of water vapor shall not be a violation of this section.

(9 VAC 5-50-290)

12. No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

(9 VAC 5-50-410 and 40 CFR 60 Subpart A 60.12)

13. In case of shutdown or bypassing, or both of air pollution control equipment for necessary scheduled maintenance for more than one hour the intent to shutdown the equipment shall be reported to the board.

(9 VAC 5-20-180 (B))

B. Monitoring

1. All continuous monitoring systems and monitoring devices, as may be applicable for your source type, shall be installed and operational prior to conducting performance tests under 9 VAC 5-50-30 and 9 VAC 5-60-30 of State Regulations. Performance evaluations of the continuous monitoring system must take place during the performance tests under Sections 9 VAC 5-50-30 and 9 VAC 5-60-30 of State Regulations or within 30 days thereafter. The Department (Director, Piedmont Regional Office) Board must be furnished with two copies of the report of the performance evaluations within 60 days of said evaluation.

(9 VAC 5-50-40 and 9 VAC 5-60-40)

2. For the purposes of §60.13, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of §60.13 upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise

specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(9 VAC 5-50-410 and 40 CFR 60 Subpart A 60.13(a))

C. Recordkeeping

1. The permittee shall retain records of all emission data and operating parameters required to be monitored by the terms of this permit. These records shall be maintained by the source for the most current Five (5) year period.
(9 VAC 5-50-50 and 9 VAC 5-60-50)
2. The permittee shall develop, maintain, and have available to all operators good written operating procedures for all air pollution control equipment. A maintenance schedule for all such equipment will be established and made available to the Department (Director, Piedmont Regional Office) for review. Records of service and maintenance will be maintained on file by the source for a period of five (5) years.
(9 VAC 5-20-110)
3. An owner of an affected facility subject to the provisions of this section shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. The records shall be maintained in a form suitable for inspection and maintained for at least two years following the date of the occurrence.
(9 VAC 5-20-180 J)
4. The owner of a stationary source shall keep records as necessary to determine its emissions. Any owner claiming that a facility is exempt from the provisions of these regulations shall keep records to demonstrate its continued exempt status.
(9 VAC 5-50-50 F)
5. Upon request of the board, the owner of a new or modified source shall provide notifications and reports, maintain records or report performance test or monitoring results in a manner and form and using procedure acceptable to the board.
(9 VAC 5-50-50 H)

D. Testing

1. The permitted facility shall be constructed so as to allow for emissions testing at any time using appropriate methods. Upon request from the Department, test ports shall be provided at the appropriate locations.
(9 VAC 5-50-30 and 9 VAC 5-80-110)

2. If testing is conducted in addition to the monitoring specified in this permit, the permittee shall use the appropriate method(s) in accordance with procedures approved by the DEQ.
(9 VAC 5-80-110)

E. Reporting

1. The permittee shall furnish notification to the Piedmont Region of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but no later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within two weeks of discovery of the malfunction. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Piedmont Region.
(9 VAC 5-20-180 C and 9 VAC 5-80-1180)
2. This permit may be modified or revoked in whole or in part for cause, including but not limited to, the following:
 - a. Violation of any terms or conditions of this permit;
 - b. Obtaining this permit by misrepresentation or failure to disclose fully all relevant facts;
 - c. A change in any condition that requires either a temporary or permanent reduction or elimination of a permitted discharge; or
 - d. Information that the permitted discharge of any pollutant poses a threat to human health, welfare, or the environment.
(9 VAC 5-20-110 and 9 VAC 5-80-10)
3. The permitted facility is to be constructed and operated as represented in the permit application referenced in Part 1, Condition No. 2 of the 10/31/00 permit. No changes in the permit application specifications or any existing facilities shall be made which alter the emissions into the ambient air or alter the impact of the facility on air quality without the prior written approval of the Board.
(9 VAC 5-20-110 and 9 VAC 5-80-110)
4. This permit approval is only applicable to the permit requirements of the Department of Air Pollution Control and does not alter permit requirements by any other local, state, or federal government agency. Hopewell Cogeneration Limited Partnership is cautioned that approval of this permit should not be construed to mean its operation is

automatically in compliance with all aspects of the Regulations for the Control and Abatement of Air Pollution. State Air Board personnel will be constantly evaluating all sources for compliance with Part V, Section 9 VAC 5-50-80 (of State Regulations - Standard for Visible Emissions, Section 9 VAC 5-50-90 of State Regulations - Standard for Fugitive Dust/Emissions, and Section 9 VAC 5-50-140 of State Regulations - Standard for Odorous Emissions. Compliance with all air pollution regulations must be a continuing, full time effort.

(9 VAC 5-20-110)

5. Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate your prompt response to requests for information to include, as appropriate: process and production data; changes in control equipment, and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact. The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.1-340 through 2.1-348 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board), and 9 VAC 5-20-150 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

(9 VAC 5-20-160)

6. The owner of any stationary source emitting 25 tons per year or more of volatile organic compounds or nitrogen oxides and located in any emissions control area designated in Appendix P of 9 VAC 5-10 shall submit an emissions statement to the board by April 15 of each year, beginning in 1993, for the emissions discharged during the previous calendar year. Emissions statements shall be prepared and submitted in accordance with the applicable procedure in Appendix S of 9 VAC 5-10.

(9 VAC 5-20-160 B)

VI. Insignificant Emission Units

The following emission units at the facility are identified in the application as insignificant emission units under 9 VAC 5-80-720:

Emission Unit No.	Emission Unit Description	Citation (9 VAC_)	Pollutant(s) Emitted (9 VAC 5-80-720 B)	Rated Capacity (9 VAC 5-80-720 C)
I1	Fuel Oil Tank No. 1	5-80-720 B.2.	VOC	1,250,000 gallons
I2	Fuel Oil Tank No. 2	5-80-720 B.2.	VOC	1,250,000 gallons
I4	Diesel Generator Fuel Oil Tank	5-80-720 B.2.	VOC	15,000 gallons
I5	Diesel Tank for Fire Pump	5-80-720 B.2.	VOC	200 gallons
I6	Propane Bottles	5-80-720 B.2.	N/A	Six 100 lb. bottles
I7	Natural Gas Piping	5-80-720 B.2.	VOC	N/A
I8	Fuel Oil Piping Fugitives	5-80-720 B.2.	VOC	N/A
I9	Paved Roads	5-80-720 B.1.	PM	N/A
I10	Oil/Water Separator	5-80-720 B.2.	VOC	< 500 gallons
I11	Used Oil Tank	5-80-720 C.3.	VOC	< 264 gallons
I12	Fuel Loading/ Unloading Areas	5-80-720 B.2.	VOC	N/A
I13	Summary of Worst Case	N/A	PM, VOC	N/A
I14	Diesel Fire Pump Engine	5-80-720 B.2.	VOC	N/A

These emission units are presumed to be in compliance with all requirements of the federal Clean Air Act as may apply. Based on this presumption, no monitoring, recordkeeping, or reporting shall be required for these emission units in accordance with 9 VAC 5-80-110.

VII. Permit Shield & Inapplicable Requirements

Compliance with the provisions of this permit shall be deemed compliance with all applicable requirements in effect as of the permit issuance date as identified in this permit. This permit shield covers only those applicable requirements covered by terms and conditions in this permit and the following requirements which have been specifically identified as being not applicable to this permitted facility:

Citation	Title of Citation	Description of Applicability
9 VAC 5-40-900 (Rule 4-8)	Particulate Matter Standard for Fuel Burning Equipment	This standard does not apply to stationary internal combustion engines, which include the combustion turbines and emergency generators. The auxiliary boilers are subject to NSPS Subpart Db, which has more stringent PM emissions limits.
9 VAC 5-40-930 (Rule 4-8)	Sulfur Dioxide Standard for Fuel Burning Equipment	This standard does not apply to stationary internal combustion engines, which include the combustion turbines and emergency generators. The auxiliary boilers are subject to NSPS Subpart Db, which has more stringent SO ₂ emissions limits.
40 CFR 60, Subpart Kb	Volatile Organic Liquid Storage Vessels Standards	This Subpart does not apply to the distillate oil storage tanks because the fuel has a maximum true vapor pressure of less than 15 kPa.
40 CFR 60, Subpart IIII	Stationary Compression Ignition Internal Combustion Engines Standards	This Subpart does not apply to the emergency generators because they were constructed before July 11, 2005.
40 CFR 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines	This Subpart does not apply to the combustion turbines since the construction of these units commenced before February 18, 2005.
40 CFR 63, Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines	This Subpart does not apply to the combustion turbines since they are considered existing units and are exempt pursuant to 40 CFR 63.6090(b)(4).
9 VAC 5-40-5220 (Rule 4-37)	VOC Standards for Petroleum Liquid Storage and Transfer Operations	This standard does not apply to the fuel oil storage tanks because it is not applicable to units storing petroleum liquids with a vapor pressure less than 1.5 pounds per square inch.

Nothing in this permit shield shall alter the provisions of §303 of the federal Clean Air Act, including the authority of the administrator under that section, the liability of the owner for any violation of applicable requirements prior to or at the time of permit issuance, or the ability to obtain information by the administrator pursuant to §114 of the federal Clean Air Act, (ii) the Board pursuant to §10.1-1314 or §10.1-1315 of the Virginia Air Pollution Control Law or (iii) the Department pursuant to §10.1-1307.3 of the Virginia Air Pollution Control Law.

(9 VAC 5-80-140)

VIII. General Conditions

A. Federal Enforceability

All terms and conditions in this permit are enforceable by the administrator and citizens under the federal Clean Air Act, except those that have been designated as only state-enforceable.

(9 VAC 5-80-110 N)

B. Permit Expiration

This permit has a fixed term of five years. The expiration date shall be the date five years from the date of issuance. Unless the owner submits a timely and complete application for renewal to the Department consistent with the requirements of 9 VAC 5-80-80, the right of the facility to operate shall be terminated upon permit expiration.

1. The owner shall submit an application for renewal at least six months but no earlier than eighteen months prior to the date of permit expiration.
2. If an applicant submits a timely and complete application for an initial permit or renewal under this section, the failure of the source to have a permit or the operation of the source without a permit shall not be a violation of Article 1, Part II of 9 VAC 5 Chapter 80, until the Board takes final action on the application under 9 VAC 5-80-150.
3. No source shall operate after the time that it is required to submit a timely and complete application under subsections C and D of 9 VAC 5-80-80 for a renewal permit, except in compliance with a permit issued under Article 1, Part II of 9 VAC 5 Chapter 80.
4. If an applicant submits a timely and complete application under section 9 VAC 5-80-80 for a permit renewal but the Board fails to issue or deny the renewal permit before the end of the term of the previous permit, (i) the previous permit shall not expire until the renewal permit has been issued or denied and (ii) all the terms and conditions of the previous permit, including any permit shield granted pursuant to 9

VAC 5-80-140, shall remain in effect from the date the application is determined to be complete until the renewal permit is issued or denied.

5. The protection under subsections F 1 and F 5 (ii) of section 9 VAC 5-80-80 F shall cease to apply if, subsequent to the completeness determination made pursuant section 9 VAC 5-80-80 D, the applicant fails to submit by the deadline specified in writing by the Board any additional information identified as being needed to process the application.

(9 VAC 5-80-80 B, C, and F, 9 VAC 5-80-110 D and 9 VAC 5-80-170 B)

C. Recordkeeping and Reporting

1. All records of monitoring information maintained to demonstrate compliance with the terms and conditions of this permit shall contain, where applicable, the following:

- a. The date, place as defined in the permit, and time of sampling or measurements.
- b. The date(s) analyses were performed.
- c. The company or entity that performed the analyses.
- d. The analytical techniques or methods used.
- e. The results of such analyses.
- f. The operating conditions existing at the time of sampling or measurement.

(9 VAC 5-80-110 F)

2. Records of all monitoring data and support information shall be retained for at least five years from the date of the monitoring sample, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit.

(9 VAC 5-80-110 F)

3. The permittee shall submit the results of monitoring contained in any applicable requirement to DEQ no later than **March 1** and **September 1** of each calendar year. This report must be signed by a responsible official, consistent with 9 VAC 5-80-80 G, and shall include:

- a. The time period included in the report. The time periods to be addressed are January 1 to June 30 and July 1 to December 31.

b. All deviations from permit requirements. For purpose of this permit, deviations include, but are not limited to:

- (1) Exceedance of emissions limitations or operational restrictions;
- (2) Excursions from control device operating parameter requirements, as documented by continuous emission monitoring, periodic monitoring, or Compliance Assurance Monitoring (CAM) which indicates an exceedance of emission limitations or operational restrictions; or,
- (3) Failure to meet monitoring, recordkeeping, or reporting requirements contained in this permit.

c. If there were no deviations from permit conditions during the time period, the permittee shall include a statement in the report that "no deviations from permit requirements occurred during this semi-annual reporting period."

(9 VAC 5-80-110 F)

D. Annual Compliance Certification

Exclusive of any reporting required to assure compliance with the terms and conditions of this permit or as part of a schedule of compliance contained in this permit, the permittee shall submit to EPA and DEQ no later than March 1 each calendar year a certification of compliance with all terms and conditions of this permit including emission limitation standards or work practices. The compliance certification shall comply with such additional requirements that may be specified pursuant to §114(a)(3) and §504(b) of the federal Clean Air Act. This certification shall be signed by a responsible official, consistent with 9 VAC 5-80-80 G, and shall include:

1. The time period included in the certification. The time period to be addressed is January 1 to December 31.
2. The identification of each term or condition of the permit that is the basis of the certification.
3. The compliance status.
4. Whether compliance was continuous or intermittent, and if not continuous, documentation of each incident of non-compliance.
5. Consistent with subsection 9 VAC 5-80-110 E, the method or methods used for determining the compliance status of the source at the time of certification and over the reporting period.
6. Such other facts as the permit may require to determine the compliance status of the source.

7. One copy of the annual compliance certification shall be sent to EPA at the following address:

Clean Air Act Title V Compliance Certification (3AP00)
U.S. Environmental Protection Agency, Region III
650 Arch Street
Philadelphia, PA 19103-2029
(9 VAC 5-80-110 K.5)

E. Permit Deviation Reporting

The permittee shall notify the Director, Piedmont Regional Office within four daytime business hours after discovery of any deviations from permit requirements which may cause excess emissions for more than one hour, including those attributable to upset conditions as may be defined in this permit. In addition, within 14 days of the discovery, the permittee shall provide a written statement explaining the problem, any corrective actions or preventative measures taken, and the estimated duration of the permit deviation. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. The occurrence should also be reported in the next semi-annual compliance monitoring report pursuant to General Condition IX.C.3 of this permit.

(9 VAC 5-80-110 F.2 and 9 VAC 5-80-250)

F. Failure/Malfunction Reporting

In the event that any affected facility or related air pollution control equipment fails or malfunctions in such a manner that may cause excess emissions for more than one hour, the owner shall, as soon as practicable but no later than four daytime business hours after the malfunction is discovered, notify the Director, Piedmont Regional Office by facsimile transmission, telephone or telegraph of such failure or malfunction and shall within 14 days of discovery provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. Owners subject to the requirements of 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not required to provide the written statement prescribed in this paragraph for facilities subject to the monitoring requirements of 9 VAC 5-40-40 and 9 VAC 5-50-40. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the owner shall notify the Director, Piedmont Regional Office.

(9 VAC 5-20-180 C)

1. The emission units that have continuous monitors subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C are not subject to the 14 day written notification.
2. The emission units subject to the reporting and the procedure requirements of 9 VAC 5-40-50 C and the procedures of 9 VAC 5-50-50 C are listed below:
 - a. Combustion Turbines (Ref. Nos. CT1, CT2, and CT3)

- b. Auxiliary Boilers (Ref. Nos. AB1 and AB2)
 - c. Emergency Generators (Ref. Nos. G1 and G2)
3. Each owner required to install a continuous monitoring system (CMS) or monitoring device subject to 9 VAC 5-40-41 or 9 VAC 5-50-410 shall submit a written report of excess emissions (as defined in the applicable subpart in 9 VAC 5-50-410) and either a monitoring systems performance report or a summary report form, or both, to the board semiannually. All semi-annual reports shall be postmarked by the 30th day following the end of each calendar semi-annual period (June 30th and January 30th). All reports shall include the following information:
- a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h) or 9 VAC 5-40-41 B.6, any conversion factors used, and the date and time of commencement and completion of each period of excess emissions;
 - b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the source. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted;
 - c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments; and
 - d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in the report.
- All malfunctions of emission units not subject to 9 VAC 5-40-50 C and 9 VAC 5-50-50 C require written reports within 14 days of the discovery of the malfunction.
(9 VAC 5-20-180 C, 9 VAC 5-40-50, and 9 VAC 5-50-50)

G. Severability

The terms of this permit are severable. If any condition, requirement or portion of the permit is held invalid or inapplicable under any circumstance, such invalidity or inapplicability shall not affect or impair the remaining conditions, requirements, or portions of the permit.
(9 VAC 5-80-110 G.1)

H. Duty to Comply

The permittee shall comply with all terms and conditions of this permit. Any permit noncompliance constitutes a violation of the federal Clean Air Act or the Virginia Air

Pollution Control Law or both and is ground for enforcement action; for permit termination, revocation and reissuance, or modification; or, for denial of a permit renewal application.
(9 VAC 5-80-110 G.2)

I. Need to Halt or Reduce Activity not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.
(9 VAC 5-80-110 G.3)

J. Permit Modification

A physical change in, or change in the method of operation of, this stationary source may be subject to permitting under State Regulations 9 VAC 5-80-50, 9 VAC 5-80-1100, 9 VAC 5-80-1605, or 9 VAC 5-80-2000 and may require a permit modification and/or revisions except as may be authorized in any approved alternative operating scenarios.
(9 VAC 5-80-190 and 9 VAC 5-80-260)

K. Property Rights

The permit does not convey any property rights of any sort, or any exclusive privilege.
(9 VAC 5-80-110 G.5)

L. Duty to Submit Information

1. The permittee shall furnish to the Board, within a reasonable time, any information that the Board may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Board copies of records required to be kept by the permit and, for information claimed to be confidential, the permittee shall furnish such records to the Board along with a claim of confidentiality.
(9 VAC 5-80-110 G.6)
2. Any document (including reports) required in a permit condition to be submitted to the Board shall contain a certification by a responsible official that meets the requirements of 9 VAC 5-80-80 G.
(9 VAC 5-80-110 K.1)

M. Duty to Pay Permit Fees

The owner of any source for which a permit under 9 VAC 5-80-50 through 9 VAC 5-80-300 was issued shall pay permit fees consistent with the requirements of 9 VAC 5-80-310 through 9 VAC 5-80-350. The actual emissions covered by the permit program fees for the preceding year shall be calculated by the owner and submitted to the Department by April 15

of each year. The calculations and final amount of emissions are subject to verification and final determination by the Department.
(9 VAC 5-80-110 H and 9 VAC 5-80-340 C)

N. Fugitive Dust Emission Standards

During the operation of a stationary source or any other building, structure, facility, or installation, no owner or other person shall cause or permit any materials or property to be handled, transported, stored, used, constructed, altered, repaired, or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Such reasonable precautions may include, but are not limited to, the following:

1. Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads, or the clearing of land;
2. Application of asphalt, water, or suitable chemicals on dirt roads, materials stockpiles, and other surfaces which may create airborne dust; the paving of roadways and the maintaining of them in a clean condition;
3. Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty material. Adequate containment methods shall be employed during sandblasting or similar operations;
4. Open equipment for conveying or transporting material likely to create objectionable air pollution when airborne shall be covered or treated in an equally effective manner at all times when in motion; and,
5. The prompt removal of spilled or tracked dirt or other materials from paved streets and of dried sediments resulting from soil erosion.

(9 VAC 5-40-90 and 9 VAC 5-50-90)

O. Startup, Shutdown, and Malfunction

At all times, including periods of startup, shutdown, and soot blowing, and malfunction, owners shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Board, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(9 VAC 5-50-20 E)

P. Alternative Operating Scenarios

Contemporaneously with making a change between reasonably anticipated operating scenarios identified in this permit, the permittee shall record in a log at the permitted facility

a record of the scenario under which it is operating. The permit shield described in 9 VAC 5-80-140 shall extend to all terms and conditions under each such operating scenario. The terms and conditions of each such alternative scenario shall meet all applicable requirements including the requirements of 9 VAC 5 Chapter 80, Article 1.
(9 VAC 5-80-110 J)

Q. Inspection and Entry Requirements

1. The permittee shall allow DEQ, upon presentation of credentials and other documents as may be required by law, to perform the following:
2. Enter upon the premises where the source is located or emissions-related activity is conducted, or where records must be kept under the terms and conditions of the permit.
3. Have access to and copy, at reasonable times, any records that must be kept under the terms and conditions of the permit.
4. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit.
5. Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit or applicable requirements.

(9 VAC 5-80-110 K.2)

R. Reopening For Cause

The permit shall be reopened by the Board if additional federal requirements become applicable to a major source with a remaining permit term of three years or more. Such reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to 9 VAC 5-80-80 F.

1. The permit shall be reopened if the Board or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.
2. The permit shall be reopened if the administrator or the Board determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

3. The permit shall not be reopened by the Board if additional applicable state requirements become applicable to a major source prior to the expiration date established under 9 VAC 5-80-110 D.

(9 VAC 5-80-110 L)

S. Permit Availability

Within five days after receipt of the issued permit, the permittee shall maintain the permit on the premises for which the permit has been issued and shall make the permit immediately available to DEQ upon request.

(9 VAC 5-80-150 E)

T. Transfer of Permits

1. No person shall transfer a permit from one location to another, unless authorized under 9 VAC 5-80-130, or from one piece of equipment to another.

(9 VAC 5-80-160)

2. In the case of a transfer of ownership of a stationary source, the new owner shall comply with any current permit issued to the previous owner. The new owner shall notify the Board of the change in ownership within 30 days of the transfer and shall comply with the requirements of 9 VAC 5-80-200.

(9 VAC 5-80-160)

3. In the case of a name change of a stationary source, the owner shall comply with any current permit issued under the previous source name. The owner shall notify the Board of the change in source name within 30 days of the name change and shall comply with the requirements of 9 VAC 5-80-200.

(9 VAC 5-80-160)

U. Malfunction as an Affirmative Defense

1. A malfunction constitutes an affirmative defense to an action brought for noncompliance with technology-based emission limitations if the requirements of paragraph 2 of this condition are met.
2. The affirmative defense of malfunction shall be demonstrated by the permittee through properly signed, contemporaneous operating logs, or other relevant evidence that show the following:
 - a. A malfunction occurred and the permittee can identify the cause or causes of the malfunction.
 - b. The permitted facility was at the time being properly operated.

- c. During the period of the malfunction the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit.
 - d. The permittee notified the Board of the malfunction within two working days following the time when the emission limitations were exceeded due to the malfunction. This notification shall include a description of the malfunction, any steps taken to mitigate emissions, and corrective actions taken. The notification may be delivered either orally or in writing. The notification may be delivered by electronic mail, facsimile transmission, telephone, or any other method that allows the permittee to comply with the deadline. This notification fulfills the requirements of 9 VAC 5-80-110 F.2.b to report promptly deviations from permit requirements. This notification does not release the permittee from the malfunction reporting requirement under 9 VAC 5-20-180 C.
- 3. In any enforcement proceeding, the permittee seeking to establish the occurrence of a malfunction shall have the burden of proof.
 - 4. The provisions of this section are in addition to any malfunction, emergency or upset provision contained in any applicable requirement.
(9 VAC 5-80-250)

V. Permit Revocation or Termination for Cause

A permit may be revoked or terminated prior to its expiration date if the owner knowingly makes material misstatements in the permit application or any amendments thereto or if the permittee violates, fails, neglects or refuses to comply with the terms or conditions of the permit, any applicable requirements, or the applicable provisions of 9 VAC 5 Chapter 80 Article 1. The Board may suspend, under such conditions and for such period of time as the Board may prescribe any permit for any grounds for revocation or termination or for any other violations of these regulations.

(9 VAC 5-80-190 C and 9 VAC 5-80-260)

W. Duty to Supplement or Correct Application

Any applicant who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrections. An applicant shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete application was filed but prior to release of a draft permit.

(9 VAC 5-80-80 E)

X. Stratospheric Ozone Protection

If the permittee handles or emits one or more Class I or II substances subject to a standard promulgated under or established by Title VI (Stratospheric Ozone Protection) of the federal Clean Air Act, the permittee shall comply with all applicable sections of 40 CFR Part 82, Subparts A to F.
(40 CFR Part 82, Subparts A-F)

Y. Asbestos Requirements

The permittee shall comply with the requirements of National Emissions Standards for Hazardous Air Pollutants (40 CFR 61) Subpart M, National Emission Standards for Asbestos as it applies to the following: Standards for Demolition and Renovation (40 CFR 61.145), Standards for Insulating Materials (40 CFR 61.148), and Standards for Waste Disposal (40 CFR 61.150).
(9 VAC 5-60-70 and 9 VAC 5-80-110 A.1)

Z. Accidental Release Prevention

If the permittee has more, or will have more than a threshold quantity of a regulated substance in a process, as determined by 40 CFR 68.115, the permittee shall comply with the requirements of 40 CFR Part 68.
(40 CFR Part 68)

AA. Changes to Permits for Emissions Trading

No permit revision shall be required under any federally approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this permit.
(9 VAC 5-80-110 I)

BB. Emissions Trading

Where the trading of emissions increases and decreases within the permitted facility is to occur within the context of this permit and to the extent that the regulations provide for trading such increases and decreases without a case-by-case approval of each emissions trade:

1. All terms and conditions required under 9 VAC 5-80-110, except subsection N, shall be included to determine compliance.
2. The permit shield described in 9 VAC 5-80-140 shall extend to all terms and conditions that allow such increases and decreases in emissions.
3. The owner shall meet all applicable requirements including the requirements of 9 VAC 5-80-50 through 9 VAC 5-80-300.

(9 VAC 5-80-110 I)

IX. Clean Air Interstate Rule (CAIR) Requirements

A. Clean Air Interstate Rule Requirements

The permittee shall comply with all applicable CAIR requirements (9 VAC 5-140-1010 *et seq.*, 9 VAC 5-140-2010 *et seq.*, 9 VAC 5-140-3010 *et seq.*, and 40 CFR Part 96) by the compliance date in the respective Part of 9 VAC 5 Chapter 140. The CAIR application in Attachment A to this document contains specific conditions and expires upon expiration of this Title V permit.

(9 VAC 5-80-110, 9 VAC 5 Chapter 140, and 40 CFR Part 96)

ENVIRONMENT CODIFIED REGULATIONS**TITLE—40 PROTECTION OF ENVIRONMENT****PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES****SUBPART DB—STANDARDS OF PERFORMANCE FOR INDUSTRIAL-COMMERCIAL-
INSTITUTIONAL STEAM GENERATING UNITS****Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam
Generating Units**

[Subpart Db revised at 72 FR 32742, June 13, 2007]

40 CFR 60.40b Applicability and delegation of authority.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NO_X) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NO_X standards under this subpart and to the sulfur dioxide (SO₂) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NO_X standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators;

§60.40) are also subject to the NO_x standards under this subpart and the PM and SO₂ standards under subpart D (§60.42 and §60.43).

(c) Affected facilities that also meet the applicability requirements under subpart J (Standards of performance for petroleum refineries; §60.104) are subject to the PM and NO_x standards under this subpart and the SO₂ standards under subpart J (§60.104).

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NO_x and PM standards under this subpart.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

(g) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act , the following authorities shall be retained by the Administrator and not transferred to a State.

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

(h) Any affected facility that meets the applicability requirements and is subject to subpart Ea, subpart Eb, or subpart AAAA of this part is not covered by this subpart.

(i) Heat recovery steam generators that are associated with combined cycle gas turbines and that meet the applicability requirements of subpart GG or KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other heat recovery steam generators that are capable of combusting more than 29 MW (100 MMBtu/hr) heat input of fossil fuel. If the heat recovery steam generator is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The gas turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel- Fired Steam Generators, §60.40).

(k) Any affected facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart Cb or subpart BBBB of this part is not covered by this subpart.

40 CFR 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act and in subpart A of this part.

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from the fuels listed in §60.42b(a), §60.43b(a), or §60.44b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit had it been operated for 8,760 hours during a calendar year at the maximum steady state design heat input capacity. In the case of steam generating units that are rented or leased, the actual heat input shall be determined based on the combined heat input from all operations of the affected facility in a calendar year.

Byproduct/waste means any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO₂) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart.

Chemical manufacturing plants mean industrial plants that are classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 28.

Coal means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17), coal refuse, and petroleum coke. Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal, coal-oil mixtures, coke oven gas, and coal-water mixtures, are also included in this definition for the purposes of this subpart.

Coal refuse means any byproduct of coal mining or coal cleaning operations with an ash content greater than 50 percent, by weight, and a heating value less than 13,900 kJ/kg (6,000 Btu/lb) on a dry basis.

Cogeneration, also known as combined heat and power, means a facility that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

Coke oven gas means the volatile constituents generated in the gaseous exhaust during the carbonization of bituminous coal to form coke.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a steam generating unit.

Conventional technology means wet flue gas desulfurization (FGD) technology, dry FGD technology, atmospheric fluidized bed combustion technology, and oil hydrosulfurization technology.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396

(incorporated by reference, see §60.17).

Dry flue gas desulfurization technology means a SO₂ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline reagent and water, whether introduced separately or as a premixed slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry flue gas desulfurization technology include but are not limited to lime and sodium.

Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a steam generating unit.

Emerging technology means any SO₂ control system that is not defined as a conventional technology under this section, and for which the owner or operator of the facility has applied to the Administrator and received approval to operate as an emerging technology under §60.49b(a)(4).

Federally enforceable means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State Implementation Plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 51.24.

Fluidized bed combustion technology means combustion of fuel in a bed or series of beds (including but not limited to bubbling bed units and circulating bed units) of limestone aggregate (or other sorbent materials) in which these materials are forced upward by the flow of combustion air and the gaseous products of combustion.

Fuel pretreatment means a process that removes a portion of the sulfur in a fuel before combustion of the fuel in a steam generating unit.

Full capacity means operation of the steam generating unit at 90 percent or more of the maximum steady-state design heat input capacity.

Gaseous fuel means any fuel that is present as a gas at ISO conditions.

Gross output means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical or mechanical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat release rate means the steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume (in cubic meters or cubic feet); the furnace volume is that volume bounded by the front furnace wall where the burner is located, the furnace side waterwall, and extending to the level just below or in front of the first row of convection pass tubes.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

High heat release rate means a heat release rate greater than 730,000 J/sec-m³ (70,000 Btu/hr-ft³).

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ISO Conditions means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

Lignite means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17).

Low heat release rate means a heat release rate of 730,000 J/sec-m³ (70,000 Btu/hr-ft³) or less.

Mass-feed stoker steam generating unit means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Municipal-type solid waste means refuse, more than 50 percent of which is waste consisting of a mixture of paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see §60.17).

Noncontinental area means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Oil means crude oil or petroleum or a liquid fuel derived from crude oil or petroleum, including distillate and residual oil.

Petroleum refinery means industrial plants as classified by the Department of Commerce under Standard Industrial Classification (SIC) Code 29.

Potential sulfur dioxide emission rate means the theoretical SO₂ emissions (nanograms per joule (ng/J) or lb/MMBtu heat input) that would result from combusting fuel in an uncleaned state and without using emission control systems.

Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

Pulp and paper mills means industrial plants that are classified by the Department of Commerce under North American Industry Classification System (NAICS) Code 322 or Standard Industrial Classification (SIC) Code 26.

Pulverized coal-fired steam generating unit means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension. This includes both conventional pulverized coal-fired and micropulverized coal-fired steam generating units. Residual oil means crude oil, fuel oil numbers 1 and 2 that have a nitrogen content greater than 0.05 weight percent, and all fuel oil numbers 4, 5 and 6, as defined by the American Society of Testing and

Materials in ASTM D396 (incorporated by reference, see §60.17).

Spreader stoker steam generating unit means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion takes place both in suspension and on the grate.

Steam generating unit means a device that combusts any fuel or byproduct/waste and produces steam or heats water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

Steam generating unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Very low sulfur oil means for units constructed, reconstructed, or modified on or before February 28, 2005, an oil that contains no more than 0.5 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 215 ng/J (0.5 lb/MMBtu) heat input. For units constructed, reconstructed, or modified after February 28, 2005, *very low sulfur oil* means an oil that contains no more than 0.3 weight percent sulfur or that, when combusted without SO₂ emission control, has a SO₂ emission rate equal to or less than 140 ng/J (0.32 lb/MMBtu) heat input.

Wet flue gas desulfurization technology means a SO₂ control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gas with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet flue gas desulfurization technology include, but are not limited to, lime, limestone, and sodium.

Wet scrubber system means any emission control device that mixes an aqueous stream or slurry with the exhaust gases from a steam generating unit to control emissions of PM or SO₂.

Wood means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including, but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

40 CFR 60.42b Standard for sulfur dioxide (SO₂).

(a) Except as provided in paragraphs (b), (c), (d), or (k) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) and the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

"Equation "

Where:

E_s = SO₂ emission limit, in ng/J or lb/MMBtu heat input;

K_a = 520 ng/J (or 1.2 lb/MMBtu);

K_b = 340 ng/J (or 0.80 lb/MMBtu);

H_a = Heat input from the combustion of coal, in J (MMBtu); and

H_b = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels or heat derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal refuse alone in a fluidized bed combustion steam generating unit shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 20 percent (0.20) of the potential SO₂ emission rate (80 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input. If coal or oil is fired with coal refuse, the affected facility is subject to paragraph (a) or (d) of this section, as applicable.

(c) On and after the date on which the performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that combusts coal or oil, either alone or in combination with any other fuel, and that uses an emerging technology for the control of SO₂ emissions, shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 50 percent of the potential SO₂ emission rate (50 percent reduction) and that contain SO₂ in excess of the emission limit determined according to the following formula:

$$E_s = \frac{(K_a H_a + K_b H_b)}{(H_a + H_b)}$$

"Equation "

Where:

E_s = SO₂ emission limit, in ng/J or lb/MM Btu heat input;

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$K_c = 260 \text{ ng/J}$ (or 0.60 lb/MMBtu);

$K_d = 170 \text{ ng/J}$ (or 0.40 lb/MMBtu);

H_c = Heat input from the combustion of coal, in J (MMBtu); and

H_d = Heat input from the combustion of oil, in J (MMBtu).

Only the heat input supplied to the affected facility from the combustion of coal and oil is counted under this section. No credit is provided for the heat input to the affected facility from the combustion of natural gas, wood, municipal-type solid waste, or other fuels, or from the heat input derived from exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

(d) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 and listed in paragraphs (d)(1), (2), (3), or (4) of this section shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J (0.5 lb/MMBtu) heat input if the affected facility combusts oil other than very low sulfur oil. Percent reduction requirements are not applicable to affected facilities under paragraphs (d)(1), (2), (3) or (4) of this section.

(1) Affected facilities that have an annual capacity factor for coal and oil of 30 percent (0.30) or less and are subject to a federally enforceable permit limiting the operation of the affected facility to an annual capacity factor for coal and oil of 30 percent (0.30) or less;

(2) Affected facilities located in a noncontinental area; or

(3) Affected facilities combusting coal or oil, alone or in combination with any fuel, in a duct burner as part of a combined cycle system where 30 percent (0.30) or less of the heat entering the steam generating unit is from combustion of coal and oil in the duct burner and 70 percent (0.70) or more of the heat entering the steam generating unit is from the exhaust gases entering the duct burner; or

(4) The affected facility burns coke oven gas alone or in combination with natural gas or very low sulfur distillate oil.

(e) Except as provided in paragraph (f) of this section, compliance with the emission limits, fuel oil sulfur limits, and/or percent reduction requirements under this section are determined on a 30-day rolling average basis.

(f) Except as provided in paragraph (j)(2) of this section, compliance with the emission limits or fuel oil sulfur limits under this section is determined on a 24-hour average basis for affected facilities that (1) have a federally enforceable permit limiting the annual capacity factor for oil to 10 percent or less, (2) combust only very low sulfur oil, and (3) do not combust any other fuel.

(g) Except as provided in paragraph (i) of this section and §60.45b(a), the SO₂ emission limits and percent reduction requirements under this section apply at all times, including periods of startup, shutdown, and malfunction.

(h) Reductions in the potential SO₂ emission rate through fuel pretreatment are not credited toward the percent reduction requirement under paragraph (c) of this section unless:

(1) Fuel pretreatment results in a 50 percent or greater reduction in potential SO₂ emissions and

(2) Emissions from the pretreated fuel (without combustion or post-combustion SO₂ control) are equal to or less than the emission limits specified in paragraph (c) of this section.

(i) An affected facility subject to paragraph (a), (b), or (c) of this section may combust very low sulfur oil or natural gas when the SO₂ control system is not being operated because of malfunction or maintenance of the SO₂ control system.

(j) Percent reduction requirements are not applicable to affected facilities combusting only very low sulfur oil. The owner or operator of an affected facility combusting very low sulfur oil shall demonstrate that the oil meets the definition of very low sulfur oil by:

(1) Following the performance testing procedures as described in §60.45b(c) or §60.45b(d), and following the monitoring procedures as described in §60.47b(a) or §60.47b(b) to determine SO₂ emission rate or fuel oil sulfur content; or (2) maintaining fuel records as described in §60.49b(r).

(k) (1) Except as provided in paragraphs (k)(2), (k)(3), and (k)(4) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, natural gas, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 8 percent (0.08) of the potential SO₂ emission rate (92 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

(2) Units firing only very low sulfur oil and/or a mixture of gaseous fuels with a potential SO₂ emission rate of 140 ng/J (0.32 lb/MMBtu) heat input or less are exempt from the SO₂ emissions limit in paragraph 60.42b(k)(1).

(3) Units that are located in a noncontinental area and that combust coal or oil shall not discharge any gases that contain SO₂ in excess of 520 ng/J (1.2 lb/MMBtu) heat input if the affected facility combusts coal, or 215 ng/J

(0.50 lb/MMBtu) heat input if the affected facility combusts oil.

(4) As an alternative to meeting the requirements under paragraph (k)(1) of this section, modified facilities that combust coal or a mixture of coal with other fuels shall not cause to be discharged into the atmosphere any gases that contain SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) heat input or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) and 520 ng/J (1.2 lb/MMBtu) heat input.

40 CFR 60.43b Standard for particulate matter (PM).

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 22 ng/J (0.051 lb/MMBtu) heat input,

(i) If the affected facility combusts only coal, or

(ii) If the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels of 10 percent (0.10) or less.

(2) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility combusts coal and other fuels and has an annual capacity factor for the other fuels greater than 10 percent (0.10) and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor greater than 10 percent (0.10) for fuels other than coal.

(3) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts coal or coal and other fuels and

(i) Has an annual capacity factor for coal or coal and other fuels of 30 percent (0.30) or less,

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less,

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for coal or coal and other solid fuels, and

(iv) Construction of the affected facility commenced after June 19, 1984, and before November 25, 1986.

(4) An affected facility burning coke oven gas alone or in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) for reducing PM or SO₂ emissions is not subject to the PM limits under §60.43b(a)

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO₂ emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if

(i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input;

(i) If the affected facility combusts only municipal-type solid waste; or

(ii) If the affected facility combusts municipal-type solid waste and other fuels and has an annual capacity

factor for the other fuels of 10 percent (0.10) or less.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts municipal-type solid waste or municipal-type solid waste and other fuels; and

(i) Has an annual capacity factor for municipal-type solid waste and other fuels of 30 percent (0.30) or less;

(ii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less;

(iii) Has a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for municipal-type solid waste, or municipal-type solid waste and other fuels; and

(iv) Construction of the affected facility commenced after June 19, 1984, but on or before November 25, 1986.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

(h) (1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), and (h)(5) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after

February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

(i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and

(ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.3 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard under §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO₂ or PM emissions is not subject to the PM limits under §60.43b(h)(1)

40 CFR 60.44b Standard for nitrogen oxides (NO_x).

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO₂) in excess of the following emission limits:

- |

		Nitrogen oxide emission limits (expressed as NO ₂) heat input	
Fuel/steam generating unit type		ng/J	lb/MMBTu
<hr/>			
(1)	Natural gas and distillate oil, except (4):.....		
0	(i) Low heat release rate.....	43	0.1
0	(ii) High heat release rate.....	86	0.2
(2)	Residual oil:.....		
0	(i) Low heat release rate.....	130	0.3
0	(ii) High heat release rate.....	170	0.4
(3)	Coal:.....		
	(i) Mass-		
	feed stoker.....	210	0.50
0	(ii) Spreader stoker and fluidized bed combustion.....	260	0.6
0	(iii) Pulverized coal.....	300	0.7
0	(iv) Lignite, except (v).....	260	0.6
0	(v) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace.....	340	0.8
	(vi) Coal-		
	derived synthetic fuels.....	210	0.50
(4)	Duct burner used in a combined cycle system:.....		
0	(i) Natural gas and distillate oil.....	86	0.2
0	(ii) Residual oil.....	170	0.4
<hr/>			

(b) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or

operator of an affected facility that simultaneously combusts mixtures of coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of a limit determined by the use of the following formula:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_c H_c)}{(H_{go} + H_{ro} + H_c)}$$

"Equation "

Where:

E_n = NO_x emission limit (expressed as NO₂), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas or distillate oil, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(c) Except as provided under paragraph (1) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal or oil, or a mixture of these fuels with natural gas, and wood, municipal-type solid waste, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit for the coal or oil, or mixtures of these fuels with natural gas combusted in the affected facility, as determined pursuant to paragraph (a) or (b) of this section, unless the affected facility has an annual capacity factor for coal or oil, or mixture of these fuels with natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, or a mixture of these fuels with natural gas.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts natural gas with wood, municipal-type solid waste, or other solid fuel, except coal, shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x in excess of 130 ng/J (0.30 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less for natural gas.

(e) Except as provided under paragraph (1) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that simultaneously combusts coal, oil, or natural gas with byproduct/waste shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit determined by the following formula unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the affected facility to an annual capacity factor of 10 percent (0.10) or less:

$$E_n = \frac{(EL_{go}H_{go}) + (EL_{ro}H_{ro}) + (EL_cH_c)}{(H_{go} + H_{ro} + H_c)}$$

"Equation "

Where:

E_n = NO_x emission limit (expressed as NO₂), ng/J (lb/MMBtu);

EL_{go} = Appropriate emission limit from paragraph (a)(1) for combustion of natural gas or distillate oil, ng/J (lb/MMBtu);

H_{go} = Heat input from combustion of natural gas, distillate oil and gaseous byproduct/waste, J (MMBtu);

EL_{ro} = Appropriate emission limit from paragraph (a)(2) for combustion of residual oil and/or byproduct/waste, ng/J (lb/MMBtu);

H_{ro} = Heat input from combustion of residual oil, J (MMBtu);

EL_c = Appropriate emission limit from paragraph (a)(3) for combustion of coal, ng/J (lb/MMBtu); and

H_c = Heat input from combustion of coal, J (MMBtu).

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility to establish a NO_x emission limit that shall apply specifically to that affected facility when the byproduct/waste is combusted. The petition shall include sufficient and appropriate data, as determined by the Administrator, such as NO_x emissions from the affected facility, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to confirm that the affected facility is unable to comply with the emission limits in paragraph (e) of this section and to determine the appropriate emission limit for the affected facility.

(1) Any owner or operator of an affected facility petitioning for a facility-specific NO_x emission limit under this section shall:

(i) Demonstrate compliance with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (1)(1) of this section, as appropriate, by conducting a 30-day

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performance test as provided in §60.46b(e). During the performance test only natural gas, distillate oil, or residual oil shall be combusted in the affected facility; and

(ii) Demonstrate that the affected facility is unable to comply with the emission limits for natural gas and distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, when gaseous or liquid byproduct/waste is combusted in the affected facility under the same conditions and using the same technological system of emission reduction applied when demonstrating compliance under paragraph (f)(1)(i) of this section.

(2) The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, shall be applicable to the affected facility until and unless the petition is approved by the Administrator. If the petition is approved by the Administrator, a facility-specific NO_x emission limit will be established at the NO_x emission level achievable when the affected facility is combusting oil or natural gas and byproduct/waste in a manner that the Administrator determines to be consistent with minimizing NO_x emissions. In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(g) Any owner or operator of an affected facility that combusts hazardous waste (as defined by 40 CFR part 261 or 40 CFR part 761) with natural gas or oil may petition the Administrator within 180 days of the initial startup of the affected facility for a waiver from compliance with the NO_x emission limit that applies specifically to that affected facility. The petition must include sufficient and appropriate data, as determined by the Administrator, on NO_x emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), the quantity of specific wastes to be combusted and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the NO_x emission limits required by this section. The owner or operator of the affected facility shall demonstrate that when hazardous waste is combusted in the affected facility, thermal destruction efficiency requirements for hazardous waste specified in an applicable federally enforceable requirement preclude compliance with the NO_x emission limits of this section. The NO_x emission limits for natural gas or distillate oil in paragraph (a)(1) of this section or for residual oil in paragraph (a)(2) or (l)(1) of this section, as appropriate, are applicable to the affected facility until and unless the petition is approved by the Administrator. (See 40 CFR 761.70 for regulations applicable to the incineration of materials containing polychlorinated biphenyls (PCB's).) In lieu of amending this subpart, a letter will be sent to the facility describing the facility-specific NO_x limit. The facility shall use the compliance procedures detailed in the letter and make the letter available to the public. If the Administrator determines it is appropriate, the conditions and requirements of the letter can be reviewed and changed at any point.

(h) For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times including periods of startup, shutdown, or malfunction.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

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(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

(1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;

(2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and

(3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_x emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction or reconstruction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_x (expressed as NO₂) in excess of the following limits:

(1) If the affected facility combusts coal, oil, or natural gas, or a mixture of these fuels, or with any other fuels: A limit of 86 ng/J (0.20 lb/MMBtu) heat input unless the affected facility has an annual capacity factor for coal, oil, and natural gas of 10 percent (0.10) or less and is subject to a federally enforceable requirement that limits operation of the facility to an annual capacity factor of 10 percent (0.10) or less for coal, oil, and natural gas; or

(2) If the affected facility has a low heat release rate and combusts natural gas or distillate oil in excess of 30 percent of the heat input on a 30-day rolling average from the combustion of all fuels, a limit determined by use of the following formula:

$$E_r = \frac{(0.10 \times H_{na}) + (0.20 \times H_r)}{(H_{na} + H_r)}$$

"Equation "

Where:

E_n = NO_x emission limit, (lb/MMBtu);

H_{go} = 30-day heat input from combustion of natural gas or distillate oil; and

H_r = 30-day heat input from combustion of any other fuel.

(3) After February 27, 2006, units where more than 10 percent of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this output-based limit must demonstrate compliance according to the procedures of §60.48Da(i) of subpart Da of this part, and must monitor emissions according to §60.49Da(c), (k), through (n) of subpart Da of this part.

40 CFR 60.45b Compliance and performance test methods and procedures for sulfur dioxide.

(a) The SO_2 emission standards under §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil and complying with the fuel based limit under §60.42b(d) or §60.42b(k)(2) are allowed to exceed the limit 30 operating days per calendar year for by-product plant maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

(1) The initial performance test shall be conducted over 30 consecutive operating days of the steam generating unit. Compliance with the SO_2 standards shall be determined using a 30-day average. The first operating day included in the initial performance test shall be scheduled within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

(2) If only coal, only oil, or a mixture of coal and oil is combusted, the following procedures are used:

(i) The procedures in Method 19 of appendix A of this part are used to determine the hourly SO_2 emission

rate (E_{ho}) and the 30-day average emission rate (E_{ao}). The hourly averages used to compute the 30-day averages are obtained from the continuous emission monitoring system (CEMS) of §60.47b(a) or (b).

(ii) The percent of potential SO_2 emission rate ($\%P_s$) emitted to the atmosphere is computed using the following formula:

$$\%P_s = 100 \left(1 - \frac{\%R_g}{100} \right) \left(1 - \frac{\%R_f}{100} \right)$$

"Equation "

Where:

$\%P_s$ = Potential SO_2 emission rate, percent;

$\%R_g$ = SO_2 removal efficiency of the control device as determined by Method 19 of appendix A of this part, in percent; and

$\%R_f$ = SO_2 removal efficiency of fuel pretreatment as determined by Method 19 of appendix A of this part, in percent.

(3) If coal or oil is combusted with other fuels, the same procedures required in paragraph (c)(2) of this section are used, except as provided in the following:

(i) An adjusted hourly SO_2 emission rate (E_{ho}^o) is used in Equation 19-19 of Method 19 of appendix A of this part to compute an adjusted 30-day average emission rate (E_{ao}^o). The E_{ho}^o is computed using the following formula:

$$E_{ho}^o = \frac{E_{ho} - E_w (1 - X_i)}{X_i}$$

"Equation "

Where:

E_{ho}^o = Adjusted hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_{ho} = Hourly SO_2 emission rate, ng/J (lb/MMBtu);

E_w = SO_2 concentration in fuels other than coal and oil combusted in the affected facility, as determined by the fuel sampling and analysis procedures in Method 19 of appendix A of this part, ng/J (lb/MMBtu). The value E_w for each fuel lot is used for each hourly average during the time that the lot is being combusted; and

X_k = Fraction of total heat input from fuel combustion derived from coal, oil, or coal and oil, as determined by applicable procedures in Method 19 of appendix A of this part.

(ii) To compute the percent of potential SO₂ emission rate (%P_s), an adjusted %R_g (%R_g^o) is computed from the adjusted E_{ao}^o from paragraph (b)(3)(i) of this section and an adjusted average SO₂ inlet rate (E_{ai}^o) using the following formula:

$$\%R_g^o = 100 \left(1.0 - \frac{E_{ao}^o}{E_{ai}^o} \right)$$

"Equation "

To compute E_{ai}^o, an adjusted hourly SO₂ inlet rate (E_{hi}^o) is used. The E_{hi}^o is computed using the following formula:

$$E_{hi}^o = \frac{E_{24} - E_s (1 - X_k)}{X_k}$$

"Equation "

Where:

E_{hi}^o = Adjusted hourly SO₂ inlet rate, ng/J (lb/MMBtu); and

E_{hi} = Hourly SO₂ inlet rate, ng/J (lb/MMBtu).

(4) The owner or operator of an affected facility subject to paragraph (b)(3) of this section does not have to measure parameters E_w or X_k if the owner or operator elects to assume that X_k = 1.0. Owners or operators of affected facilities who assume X_k = 1.0 shall:

(i) Determine %P_s following the procedures in paragraph (c)(2) of this section; and

(ii) Sulfur dioxide emissions (E_s) are considered to be in compliance with SO₂ emission limits under §60.42b.

(5) The owner or operator of an affected facility that qualifies under the provisions of §60.42b(d) does not have to measure parameters E_w or X_k under paragraph (b)(3) of this section if the owner or operator of the affected facility elects to measure SO₂ emission rates of the coal or oil following the fuel sampling and analysis procedures under Method 19 of appendix A of this part.

(d) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility that combusts only very low sulfur oil, has an annual capacity factor for oil of 10 percent (0.10) or less, and is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor for oil of 10 percent (0.10) or less shall:

(1) Conduct the initial performance test over 24 consecutive steam generating unit operating hours at full load;

(2) Determine compliance with the standards after the initial performance test based on the arithmetic average of the hourly emissions data during each steam generating unit operating day if a CEMS is used, or based on a daily average if Method 6B of appendix A of this part or fuel sampling and analysis procedures under Method 19 of appendix A of this part are used.

(e) The owner or operator of an affected facility subject to §60.42b(d)(1) shall demonstrate the maximum design capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. This demonstration will be made during the initial performance test and a subsequent demonstration may be requested at any other time. If the 24-hour average firing rate for the affected facility is less than the maximum design capacity provided by the manufacturer of the affected facility, the 24-hour average firing rate shall be used to determine the capacity utilization rate for the affected facility, otherwise the maximum design capacity provided by the manufacturer is used.

(f) For the initial performance test required under §60.8, compliance with the SO₂ emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO₂ for the first 30 consecutive steam generating unit operating days, except as provided under paragraph (d) of this section. The initial performance test is the only test for which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first steam generating unit operating day of the 30 successive steam generating unit operating days is completed within 30 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility. The boiler load during the 30-day period does not have to be the maximum design load, but must be representative of future operating conditions and include at least one 24-hour period at full load.

(g) After the initial performance test required under §60.8, compliance with the SO₂ emission limits and percent reduction requirements under §60.42b is based on the average emission rates and the average percent reduction for SO₂ for 30 successive steam generating unit operating days, except as provided under paragraph (d). A separate performance test is completed at the end of each steam generating unit operating day after the initial performance test, and a new 30-day average emission rate and percent reduction for SO₂ are calculated to show compliance with the standard.

(h) Except as provided under paragraph (i) of this section, the owner or operator of an affected facility shall use all valid SO₂ emissions data in calculating %P_s and E_{ho} under paragraph (c), of this section whether or not the

minimum emissions data requirements under §60.46b are achieved. All valid emissions data, including valid SO₂ emission data collected during periods of startup, shutdown and malfunction, shall be used in calculating %P_s and E_{ho} pursuant to paragraph (c) of this section.

(i) During periods of malfunction or maintenance of the SO₂ control systems when oil is combusted as provided under §60.42b(i), emission data are not used to calculate %P_s or E_s under §60.42b(a), (b) or (c), however, the emissions data are used to determine compliance with the emission limit under §60.42b(i).

(j) The owner or operator of an affected facility that combusts very low sulfur oil is not subject to the compliance and performance testing requirements of this section if the owner or operator obtains fuel receipts as described in §60.49b(r).

(k) The owner or operator of an affected facility seeking to demonstrate compliance under §§60.42b(d)(4), 60.42b(j), and 60.42b(k)(2) shall follow the applicable procedures under §60.49b(r).

40 CFR 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_x emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_x emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

(1) Method 3B of appendix A of this part is used for gas analysis when applying Method 5 or 17 of appendix A of this part.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (32 °F). The procedures of sections 2.1 and 2.3 of Method 5B of appendix A of this part may be used in Method 17 of appendix A of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

(5) For determination of PM emissions, the oxygen (O₂) or CO₂ sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

(i) The O₂ or CO₂ measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

(e) To determine compliance with the emission limits for NO_x required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_x under §60.48(b).

(1) For the initial compliance test, NO_x from the steam generating unit are monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the NO_x emission standards under §60.44b. The 30-day average emission rate is calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(2) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility which combusts coal or which combusts residual oil having a nitrogen content greater than 0.30 weight percent shall determine compliance with the NO_x emission standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(3) Following the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity greater than 73 MW (250 MMBtu/hr) and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall determine compliance with the NO_x standards under §60.44b on a continuous basis through the use of a 30-day rolling average emission rate. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(4) Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_x standards under §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_x emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) are used to calculate a 30-day rolling average emission rate on a daily basis and used to prepare excess emission reports, but will not be used to determine compliance with the NO_x emission standards. A new 30-day rolling average emission rate is calculated each steam generating unit operating day as the average of all of the hourly NO_x emission data for the preceding 30 steam generating unit operating days.

(5) If the owner or operator of an affected facility that combusts residual oil does not sample and analyze the residual oil for nitrogen content, as specified in §60.49b(e), the requirements of §60.48b(g)(1) apply and the provisions of §60.48b(g)(2) are inapplicable.

(f) To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

(1) The owner or operator of an affected facility shall conduct the performance test required under §60.8 as follows:

(i) The emissions rate (E) of NO_x shall be computed using Equation 1 in this section:

$$E = E_{sg} + \left(\frac{H_g}{H_b} \right) (E_{sg} - E_g) \quad (\text{Eq. 1})$$

"Equation 1 "

Where:

E = Emissions rate of NO_x from the duct burner, ng/J (lb/MMBtu) heat input;

E_{sg} = Combined effluent emissions rate, in ng/J (lb/MMBtu) heat input using appropriate F factor as described in Method 19 of appendix A of this part;

H_g = Heat input rate to the combustion turbine, in J/hr (MMBtu/hr);

H_b = Heat input rate to the duct burner, in J/hr (MMBtu/hr); and

E_g = Emissions rate from the combustion turbine, in ng/J (lb/MMBtu) heat input calculated using appropriate F factor as described in Method 19 of appendix A of this part.

(ii) Method 7E of appendix A of this part shall be used to determine the NO_x concentrations. Method 3A or 3B of appendix A of this part shall be used to determine O₂ concentration.

(iii) The owner or operator shall identify and demonstrate to the Administrator's satisfaction suitable methods to determine the average hourly heat input rate to the combustion turbine and the average hourly heat input rate to the affected duct burner.

(iv) Compliance with the emissions limits under §60.44b(a)(4) or §60.44b(l) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests; or

(2) The owner or operator of an affected facility may elect to determine compliance on a 30-day rolling average basis by using the CEMS specified under §60.48b for measuring NO_x and O₂ and meet the requirements of §60.48b . The sampling site shall be located at the outlet from the steam generating unit. The NO_x emissions rate at the outlet from the steam generating unit shall constitute the NO_x emissions rate from the duct burner of the combined cycle system.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference,

see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

(1) Conduct an initial performance test as required under §60.8 over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_x emission standards under §60.44b using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods; and

(2) Conduct subsequent performance tests once per calendar year or every 400 hours of operation (whichever comes first) to demonstrate compliance with the NO_x emission standards under §60.44b over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, 7E of appendix A of this part, or other approved reference methods.

(i) The owner or operator of an affected facility seeking to demonstrate compliance under paragraph §60.43b(h)(5) shall follow the applicable procedures under §60.49b(r).

(j) In place of PM testing with EPA Reference Method 5, 5B, or 17 of appendix A of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using EPA Method 5, 5B, or 17 of appendix A of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(13) of this section.

(1) Notify the Administrator one month before starting use of the system.

(2) Notify the Administrator one month before stopping use of the system.

(3) The monitor shall be installed, evaluated, and operated in accordance with §60.13 of subpart A of this part.

(4) The initial performance evaluation shall be completed no later than 180 days after the date of initial

startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of notification to the Administrator of use of the CEMS if the owner or operator was previously determining compliance by Method 5, 5B, or 17 of appendix A of this part performance tests, whichever is later.

(5) The owner or operator of an affected facility shall conduct an initial performance test for PM emissions as required under §60.8 of subpart A of this part. Compliance with the PM emission limit shall be determined by using the CEMS specified in paragraph (j) of this section to measure PM and calculating a 24-hour block arithmetic average emission concentration using EPA Reference Method 19 of appendix A of this part, section 4.1.

(6) Compliance with the PM emission limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emission concentrations using CEMS outlet data.

(7) At a minimum, valid CEMS hourly averages shall be obtained as specified in paragraphs (j)(7)(i) of this section for 75 percent of the total operating hours per 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(8) The 1-hour arithmetic averages required under paragraph (j)(7) of this section shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(9) All valid CEMS data shall be used in calculating average emission concentrations even if the minimum CEMS data requirements of paragraph (j)(7) of this section are not met.

(10) The CEMS shall be operated according to Performance Specification 11 in appendix B of this part.

(11) During the correlation testing runs of the CEMS required by Performance Specification 11 in appendix B of this part, PM and O₂ (or CO₂) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and the test methods specified in paragraphs (j)(7)(i) of this section.

(i) For PM, EPA Reference Method 5, 5B, or 17 of appendix A of this part shall be used.

(ii) For O₂ (or CO₂), EPA reference Method 3, 3A, or 3B of appendix A of this part, as applicable shall be used.

(12) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

(13) When PM emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 of appendix A of this part to provide, as necessary, valid emissions data for a minimum of 75 percent of total operating hours per 30-day rolling average.

40 CFR 60.47b Emission monitoring for sulfur dioxide.

(a) Except as provided in paragraphs (b), (f), and (h) of this section, the owner or operator of an affected facility subject to the SO₂ standards under §60.42b shall install, calibrate, maintain, and operate CEMS for measuring SO₂ concentrations and either O₂ or CO₂ concentrations and shall record the output of the systems. For units complying with the percent reduction standard, the SO₂ and either O₂ or CO₂ concentrations shall both be monitored at the inlet and outlet of the SO₂ control device. If the owner or operator has installed and certified SO₂ and O₂ or CO₂ CEMS according to the requirements of §75.20(c)(1) of this chapter and appendix A to part 75 of this chapter, and is continuing to meet the ongoing quality assurance requirements of §75.21 of this chapter and appendix B to part 75 of this chapter, those CEMS may be used to meet the requirements of this section, provided that:

(1) When relative accuracy testing is conducted, SO₂ concentration data and CO₂ (or O₂) data are collected simultaneously; and

(2) In addition to meeting the applicable SO₂ and CO₂ (or O₂) relative accuracy specifications in Figure 2 of appendix B to part 75 of this chapter, the relative accuracy (RA) standard in section 13.2 of Performance Specification 2 in appendix B to this part is met when the RA is calculated on a lb/MMBtu basis; and

(3) The reporting requirements of §60.49b are met. SO₂ and CO₂ (or O₂) data used to meet the requirements of §60.49b shall not include substitute data values derived from the missing data procedures in subpart D of part 75 of this chapter, nor shall the SO₂ data have been bias adjusted according to the procedures of part 75 of this chapter.

(b) As an alternative to operating CEMS as required under paragraph (a) of this section, an owner or operator may elect to determine the average SO₂ emissions and percent reduction by:

(1) Collecting coal or oil samples in an as-fired condition at the inlet to the steam generating unit and analyzing them for sulfur and heat content according to Method 19 of appendix A of this part. Method 19 of appendix A of this part provides procedures for converting these measurements into the format to be used in calculating the average SO₂ input rate, or

(2) Measuring SO₂ according to Method 6B of appendix A of this part at the inlet or outlet to the SO₂ control system. An initial stratification test is required to verify the adequacy of the Method 6B of appendix A of this part sampling location. The stratification test shall consist of three paired runs of a suitable SO₂ and CO₂ measurement train operated at the candidate location and a second similar train operated according to the procedures in section 3.2 and the applicable procedures in section 7 of Performance Specification 2. Method 6B of appendix A of this part, Method 6A of appendix A of this part, or a combination of Methods 6 and 3 or 3B of appendix A of this part or Methods 6C and 3A of appendix A of this part are suitable measurement techniques. If Method 6B of appendix A of this part is used for the second train, sampling time and timer operation may be adjusted for the stratification test as long as an adequate sample volume is collected; however, both sampling trains are to be operated similarly. For the location to be adequate for Method 6B of appendix A of this part 24-hour tests, the mean of the absolute difference between the three paired runs must be less than 10 percent.

(3) A daily SO₂ emission rate, E_D, shall be determined using the procedure described in Method 6A of appendix A of this part, section 7.6.2 (Equation 6A-8) and stated in ng/J (lb/MMBtu) heat input.

(4) The mean 30-day emission rate is calculated using the daily measured values in ng/J (lb/MMBtu) for 30 successive steam generating unit operating days using equation 19-20 of Method 19 of appendix A of this part.

(c) The owner or operator of an affected facility shall obtain emission data for at least 75 percent of the operating hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement is not met with a single monitoring system, the owner or operator of the affected facility shall supplement the emission data with data collected with other monitoring systems as approved by the Administrator or the reference methods and procedures as described in paragraph (b) of this section.

(d) The 1-hour average SO₂ emission rates measured by the CEMS required by paragraph (a) of this section and required under §60.13(h) is expressed in ng/J or lb/MMBtu heat input and is used to calculate the average emission rates under §60.42(b). Each 1-hour average SO₂ emission rate must be based on 30 or more minutes of steam generating unit operation. The hourly averages shall be calculated according to §60.13(h)(2). Hourly SO₂ emission rates are not calculated if the affected facility is operated less than 30 minutes in a given clock hour and are not counted toward determination of a steam generating unit operating day.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the CEMS.

(1) Except as provided for in paragraph (e)(4) of this section, all CEMS shall be operated in accordance with the applicable procedures under Performance Specifications 1, 2, and 3 of appendix B of this part.

(2) Except as provided for in paragraph (e)(4) of this section, quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 1 of appendix F of this part.

(3) For affected facilities combusting coal or oil, alone or in combination with other fuels, the span value of the SO₂ CEMS at the inlet to the SO₂ control device is 125 percent of the maximum estimated hourly potential SO₂ emissions of the fuel combusted, and the span value of the CEMS at the outlet to the SO₂ control device is 50 percent of the maximum estimated hourly potential SO₂ emissions of the fuel combusted. Alternatively, SO₂ span values determined according to section 2.1.1 in appendix A to part 75 of this chapter may be used.

(4) As an alternative to meeting the requirements of paragraphs (e)(1) and (e)(2) of this section, the owner or operator may elect to implement the following alternative data accuracy assessment procedures:

(i) For all required CO₂ and O₂ monitors and for SO₂ and NO_x monitors with span values less than 100 ppm, the daily calibration error test and calibration adjustment procedures described in sections 2.1.1 and 2.1.3 of appendix B to part 75 of this chapter may be followed instead of the CD assessment procedures in Procedure 1, section 4.1 of appendix F to this part. If this option is selected, the data validation and out-of-control provisions in sections 2.1.4 and 2.1.5 of appendix B to part 75 of this chapter shall be followed instead of the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part. For the purposes of data validation under this subpart, the excessive CD and out-of-control criteria in Procedure 1, section 4.3 of appendix F to this part shall apply to SO₂ and NO_x span values less than 100 ppm;

(ii) For all required CO₂ and O₂ monitors and for SO₂ and NO_x monitors with span values greater than 30 ppm, quarterly linearity checks may be performed in accordance with section 2.2.1 of appendix B to part 75 of this chapter, instead of performing the cylinder gas audits (CGAs) described in Procedure 1, section 5.1.2 of appendix F to this part. If this option is selected: The frequency of the linearity checks shall be as specified in section 2.2.1 of appendix B to part 75 of this chapter; the applicable linearity specifications in section 3.2 of appendix A to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.2.3 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.2.4 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the cylinder gas audits described in Procedure 1, section 5.1.2 of appendix F to this part shall be performed for SO₂ and NO_x span values less than or equal to 30 ppm; and

(iii) For SO₂, CO₂, and O₂ monitoring systems and for NO_x emission rate monitoring systems, RATAs may be performed in accordance with section 2.3 of appendix B to part 75 of this chapter instead of following the procedures described in Procedure 1, section 5.1.1 of appendix F to this part. If this option is selected: The frequency of each RATA shall be as specified in section 2.3.1 of appendix B to part 75 of this chapter; the applicable relative accuracy specifications shown in Figure 2 in appendix B to part 75 of this chapter shall be met; the data validation and out-of-control criteria in section 2.3.2 of appendix B to part 75 of this chapter shall be followed instead of the excessive audit inaccuracy and out-of-control criteria in Procedure 1, section 5.2 of appendix F to this part; and the grace period provisions in section 2.3.3 of appendix B to part 75 of this chapter shall apply. For the purposes of data validation under this subpart, the relative accuracy specification in section 13.2 of Performance Specification 2 in appendix B to this part shall be met on a lb/MMBtu basis for SO₂ (regardless of the SO₂ emission level during the RATA), and for NO_x when the average NO_x emission rate

measured by the reference method during the RATA is less than 0.100 lb/MMBtu.

(f) The owner or operator of an affected facility that combusts very low sulfur oil or is demonstrating compliance under §60.45b(k) is not subject to the emission monitoring requirements under paragraph (a) of this section if the owner or operator maintains fuel records as described in §60.49b(r).

40 CFR 60.48b Emission monitoring for particulate matter and nitrogen oxides.

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a CEMS for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

(1) Install, calibrate, maintain, and operate CEMS for measuring NO_x and O₂ (or CO₂) emissions discharged to the atmosphere, and shall record the output of the system; or

(2) If the owner or operator has installed a NO_x emission rate CEMS to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_x is determined using one of the following procedures:

(i) Except as provided under paragraph (e)(2)(ii) of this section, NO_x span values shall be determined as follows:

Fuel	Span values for NO _x (ppm)
Natural gas.....	500.
Oil.....	500.
Coal.....	1,000.
Mixtures.....	$500 (x + y) + 1,000z.$

Where:

x = Fraction of total heat input derived from natural gas;

y = Fraction of total heat input derived from oil; and

z = Fraction of total heat input derived from coal.

(ii) As an alternative to meeting the requirements of paragraph (e)(2)(i) of this section, the owner or operator of an affected facility may elect to use the NO_x span values determined according to section 2.1.2 in appendix A to part 75 of this chapter.

(3) All span values computed under paragraph (e)(2)(i) of this section for combusting mixtures of regulated fuels are rounded to the nearest 500 ppm. Span values computed under paragraph (e)(2)(ii) of this section shall be rounded off according to section 2.1.2 in appendix A to part 75 of this chapter.

(f) When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less,

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natural gas, distillate oil, or any mixture of these fuels, greater than 10 percent (0.10) shall:

- (1) Comply with the provisions of paragraphs (b), (c), (d), (e)(2), (e)(3), and (f) of this section; or
- (2) Monitor steam generating unit operating conditions and predict NO_x emission rates as specified in a plan submitted pursuant to §60.49b(c).
- (h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_x standards of §60.44b(a)(4) or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.
- (i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_x emissions.
- (j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), or (5) of this section is not required to install or operate a COMS for measuring opacity if:
 - (1) The affected facility uses a PM CEMS to monitor PM emissions; or
 - (2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO₂ emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO₂ or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or
 - (3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO₂ or PM emissions; or
 - (4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO₂, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section.
- (i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.
 - (A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in

§60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. At least two data points per hour must be used to calculate each 1-hour average.

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the appropriate delegated permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS monitor instead of monitoring opacity must calibrate, maintain, and operate a CEMS, and record the output of the system, for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

40 CFR 60.49b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §§60.42b(d)(1), 60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), 60.44b(c), (d), (e), (i), (j), (k), 60.45b(d), (g), 60.46b(h), or 60.48b(i);

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired; and

(4) Notification that an emerging technology will be used for controlling emissions of SO₂. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

(b) The owner or operator of each affected facility subject to the SO₂, PM, and/or NO_x emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

(c) The owner or operator of each affected facility subject to the NO_x standard of §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions under the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored under §60.48b(g)(2) and the records to be maintained under §60.49b(j). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

(1) Identify the specific operating conditions to be monitored and the relationship between these operating

conditions and NO_x emission rates (*i.e.*, ng/J or lbs/MMBtu heat input). Steam generating unit operating conditions include, but are not limited to, the degree of staged combustion (*i.e.*, the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.*, flue gas O₂ level);

(2) Include the data and information that the owner or operator used to identify the relationship between NO_x emission rates and these operating conditions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under §60.48b(g) on an hourly basis by the owner or operator during the period of operation of the affected facility; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating conditions will be representative and accurate; and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under §60.49b(j).

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

(e) For an affected facility that combusts residual oil and meets the criteria under §§60.46b(e)(4), 60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

(f) For facilities subject to the opacity standard under §60.43b, the owner or operator shall maintain records of opacity.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_x standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The average hourly NO_x emission rates (expressed as NO₂) (ng/J or lb/MMBtu heat input) measured or predicted;

(3) The 30-day average NO_x emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each

steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

(4) Identification of the steam generating unit operating days when the calculated 30-day average NO_x emission rates are in excess of the NO_x emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

(8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

(1) Any affected facility subject to the opacity standards under §60.43b(e) or to the operating parameter monitoring requirements under §60.13(i)(1).

(2) Any affected facility that is subject to the NO_x standard of §60.44b, and that:

(i) Combusts natural gas, distillate oil, or residual oil with a nitrogen content of 0.3 weight percent or less;
or

(ii) Has a heat input capacity of 73 MW (250 MMBtu/hr) or less and is required to monitor NO_x emissions on a continuous basis under §60.48b(g)(1) or steam generating unit operating conditions under §60.48b(g)(2).

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

(j) The owner or operator of any affected facility subject to the SO₂ standards under §60.42b shall submit reports.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the Administrator:

(1) Calendar dates covered in the reporting period;

(2) Each 30-day average SO₂ emission rate (ng/J or lb/MMBtu heat input) measured during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(3) Each 30-day average percent reduction in SO₂ emissions calculated during the reporting period, ending with the last 30-day period; reasons for noncompliance with the emission standards; and a description of corrective actions taken;

(4) Identification of the steam generating unit operating days that coal or oil was combusted and for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours in the steam generating unit operating day; justification for not obtaining sufficient data; and description of corrective action taken;

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;

- (7) Identification of times when hourly averages have been obtained based on manual sampling methods;
 - (8) Identification of the times when the pollutant concentration exceeded full span of the CEMS;
 - (9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3;
 - (10) Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part; and
 - (11) The annual capacity factor of each fired as provided under paragraph (d) of this section.
- (l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:
- (1) Calendar dates when the facility was in operation during the reporting period;
 - (2) The 24-hour average SO₂ emission rate measured for each steam generating unit operating day during the reporting period that coal or oil was combusted, ending in the last 24-hour period in the quarter; reasons for noncompliance with the emission standards; and a description of corrective actions taken;
 - (3) Identification of the steam generating unit operating days that coal or oil was combusted for which SO₂ or diluent (O₂ or CO₂) data have not been obtained by an approved method for at least 75 percent of the operating hours; justification for not obtaining sufficient data; and description of corrective action taken;
 - (4) Identification of the times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and description of corrective action taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit;
 - (5) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted;
 - (6) Identification of times when hourly averages have been obtained based on manual sampling methods;
 - (7) Identification of the times when the pollutant concentration exceeded full span of the CEMS;
 - (8) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

(9) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of appendix F 1 of this part. If the owner or operator elects to implement the alternative data assessment procedures described in §§60.47b(e)(4)(i) through (e)(4)(iii), each data assessment report shall include a summary of the results of all of the RATAs, linearity checks, CGAs, and calibration error or drift assessments required by §§60.47b(e)(4)(i) through (e)(4)(iii).

(m) For each affected facility subject to the SO₂ standards under §60.42(b) for which the minimum amount of data required under §60.47b(f) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

- (1) The number of hourly averages available for outlet emission rates and inlet emission rates;
 - (2) The standard deviation of hourly averages for outlet emission rates and inlet emission rates, as determined in Method 19 of appendix A of this part, section 7;
 - (3) The lower confidence limit for the mean outlet emission rate and the upper confidence limit for the mean inlet emission rate, as calculated in Method 19 of appendix A of this part, section 7; and
 - (4) The ratio of the lower confidence limit for the mean outlet emission rate and the allowable emission rate, as determined in Method 19 of appendix A of this part, section 7.
- (n) If a percent removal efficiency by fuel pretreatment (*i.e.*, %R_f) is used to determine the overall percent reduction (*i.e.*, %R_o) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

- (1) Indicating what removal efficiency by fuel pretreatment (*i.e.*, %R_f) was credited during the reporting period;
- (2) Listing the quantity, heat content, and date each pre-treated fuel shipment was received during the reporting period, the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the reporting period;
- (3) Documenting the transport of the fuel from the fuel pretreatment facility to the steam generating unit; and
- (4) Including a signed statement from the owner or operator of the fuel pretreatment facility certifying that the percent removal efficiency achieved by fuel pretreatment was determined in accordance with the provisions of Method 19 of appendix A of this part and listing the heat content and sulfur content of each fuel before and after fuel pretreatment.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

- (1) Calendar date;
- (2) The number of hours of operation; and
- (3) A record of the hourly steam load.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

- (1) The annual capacity factor over the previous 12 months;
- (2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and
- (3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_x emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_x emission test.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

(1) The owner or operator of an affected facility who elects to demonstrate that the affected facility combusts only very low sulfur oil under §60.42b(j)(2) or §60.42b(k)(2) shall obtain and maintain at the affected facility fuel receipts from the fuel supplier that certify that the oil meets the definition of distillate oil as defined in §60.41b and the applicable sulfur limit. For the purposes of this section, the distillate oil need not meet the fuel nitrogen content specification in the definition of distillate oil. Reports shall be submitted to the Administrator certifying that only very low sulfur oil meeting this definition and/or pipeline quality natural gas was combusted in the affected facility during the reporting period; or

(2) The owner or operator of an affected facility who elects to demonstrate compliance based on fuel analysis in §60.42b or §60.43b shall develop and submit a site-specific fuel analysis plan to the Administrator for review and approval no later than 60 days before the date you intend to demonstrate compliance. Each fuel analysis plan shall include a minimum initial requirement of weekly testing and each analysis report shall contain, at a

minimum, the following information:

- (i) The potential sulfur emissions rate of the representative fuel mixture in ng/J heat input;
 - (ii) The method used to determine the potential sulfur emissions rate of each constituent of the mixture. For distillate oil and natural gas a fuel receipt or tariff sheet is acceptable;
 - (iii) The ratio of different fuels in the mixture; and
 - (iv) The owner or operator can petition the Administrator to approve monthly or quarterly sampling in place of weekly sampling.
- (s) Facility specific NO_x standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

(1) Definitions.

Oxidation zone is defined as the portion of the C.AOG incinerator that extends from the inlet of the oxidizing zone combustion air to the outlet gas stack.

Reducing zone is defined as the portion of the C.AOG incinerator that extends from the burner section to the inlet of the oxidizing zone combustion air.

Total inlet air is defined as the total amount of air introduced into the C.AOG incinerator for combustion of natural gas and chemical by-product waste and is equal to the sum of the air flow into the reducing zone and the air flow into the oxidation zone.

(2) Standard for nitrogen oxides.

- (i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a)(i) applies.
- (ii) When natural gas and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 289 ng/J (0.67 lb/MMBtu) and a maximum of 81 percent of the total inlet air provided for combustion shall be provided to the reducing zone of the C.AOG incinerator.

(3) Emission monitoring.

- (i) The percent of total inlet air provided to the reducing zone shall be determined at least every 15 minutes by measuring the air flow of all the air entering the reducing zone and the air flow of all the air entering the oxidation zone, and compliance with the percentage of total inlet air that is provided to the reducing zone shall be

determined on a 3-hour average basis.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b(i).

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with §60.48b.

(4) Reporting and recordkeeping requirements.

(i) The owner or operator of the C.AOG incinerator shall submit a report on any excursions from the limits required by paragraph (a)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the C.AOG incinerator shall keep records of the monitoring required by paragraph (a)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the C.AOG incinerator shall perform all the applicable reporting and recordkeeping requirements of this section.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

(1) Definitions.

Air ratio control damper is defined as the part of the low NO_x burner that is adjusted to control the split of total combustion air delivered to the reducing and oxidation portions of the combustion flame.

Flue gas recirculation line is defined as the part of Boiler No. 100 that recirculates a portion of the boiler flue gas back into the combustion air.

(2) Standard for nitrogen oxides.

(i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by-product waste are simultaneously combusted, the NO_x emission limit is 473 ng/J (1.1 lb/MMBtu), and the air ratio control damper tee handle shall be at a minimum of 5 inches (12.7 centimeters) out of the boiler, and the flue gas recirculation line shall be operated at a minimum of 10 percent open as indicated by its valve opening position indicator.

(3) *Emission monitoring for nitrogen oxides.*

(i) The air ratio control damper tee handle setting and the flue gas recirculation line valve opening position indicator setting shall be recorded during each 8-hour operating shift.

(ii) The NO_x emission limit shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(iii) The monitoring of the NO_x emission limit shall be performed in accordance with §60.48b.

(4) *Reporting and recordkeeping requirements.*

(i) The owner or operator of Boiler No. 100 shall submit a report on any excursions from the limits required by paragraph (b)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of Boiler No. 100 shall keep records of the monitoring required by paragraph (b)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of Boiler No. 100 shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.*

(1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

(i) The site shall equip the natural gas-fired boilers with low NO_x technology.

(ii) The site shall install, calibrate, maintain, and operate a continuous monitoring and recording system for measuring NO_x emissions discharged to the atmosphere and opacity using a continuous emissions monitoring system or a predictive emissions monitoring system.

(iii) Within 180 days of the completion of the powerhouse conversion, as required by 40 CFR 52.2454, the site shall perform a performance test to quantify criteria pollutant emissions.

(2) [Reserved]

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO₂ and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

(1) *Standard for nitrogen oxides.*

(i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical by- product waste are simultaneously combusted, the NO_x emission limit is 215 ng/J (0.5 lb/MMBtu).

(2) *Emission monitoring for nitrogen oxides.*

(i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.*

(i) The owner or operator of the No. 2 Power Boiler shall submit a report on any excursions from the limits required by paragraph (x)(2) of this section to the Administrator with the quarterly report required by §60.49b(i).

(ii) The owner or operator of the No. 2 Power Boiler shall keep records of the monitoring required by

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paragraph (x)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the No. 2 Power Boiler shall perform all the applicable reporting and recordkeeping requirements of §60.49b.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

(1) *Standard for NO_x.*

(i) When fossil fuel alone is combusted, the NO_x emission limit for fossil fuel in §60.44b(a) applies.

(ii) When fossil fuel and chemical byproduct/waste are simultaneously combusted, the NO_x emission limit is 645 ng/J (1.5 lb/MMBtu).

(2) *Emission monitoring for NO_x.*

(i) The NO_x emissions shall be determined by the compliance and performance test methods and procedures for NO_x in §60.46b.

(ii) The monitoring of the NO_x emissions shall be performed in accordance with §60.48b.

(3) *Reporting and recordkeeping requirements.*

(i) The owner or operator of the AOGI shall submit a report on any excursions from the limits required by paragraph (y)(2) of this section to the Administrator with the quarterly report required by paragraph (i) of this section.

(ii) The owner or operator of the AOGI shall keep records of the monitoring required by paragraph (y)(3) of this section for a period of 2 years following the date of such record.

(iii) The owner or operator of the AOGI shall perform all the applicable reporting and recordkeeping requirements of this section.

ENVIRONMENT CODIFIED REGULATIONS**TITLE—40 PROTECTION OF ENVIRONMENT****PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES****SUBPART GG—STANDARDS OF PERFORMANCE FOR STATIONARY GAS TURBINES****Subpart GG—Standards of Performance for Stationary Gas Turbines****40 CFR 60.330 Applicability and designation of affected facility.**

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

[§60.330(a) amended at 65 FR 61759, Oct. 17, 2000]

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

40 CFR 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas; or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) *Unit operating hour* means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

[§60.331(s) removed at 65 FR 61759, Oct. 17, 2000; added at 68 FR 17997, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(t) *Excess emissions* means a specified averaging period over which either:

(1) The NO_x emissions are higher than the applicable emission limit in §60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in §60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

[§60.331(t) added at 68 FR 17997, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(u) *Natural gas* means a naturally occurring fluid mixture of hydrocarbons (*e.g.*, methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

[§60.331(u) added at 68 FR 17997, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(v) *Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, *etc.*, to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

[§60.331(v) added at 68 FR 17998, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR

41359, July 8, 2004]

(w) *Lean premix stationary combustion turbine* means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

[§60.331(w) added at 68 FR 17998, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(x) *Diffusion flame stationary combustion turbine* means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

[§60.331(x) added at 68 FR 17998, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(y) *Unit operating day* means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

[§60.331(y) added at 68 FR 17998, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41359, July 8, 2004]

(z) *Unit operating day* [Withdrawn]

[§60.331(z) added at 68 FR 17998, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003]

40 CFR 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by §60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

[§60.332(a) introductory text amended at 65 FR 61759, Oct. 17, 2000]

(l) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

"Equation"

Where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

[§60.332(a)(1) equation definitions amended at 68 FR 17998 , April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; amended at 69 FR 41359, July 8, 2004]

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150 \frac{(14.4)}{Y} + F$$

"Equation"

Where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

[§60.332(a)(2) equation definitions amended at 68 FR 17998 , April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; amended at 69 FR 41359, July 8, 2004]

(3) The use of F in paragraphs (a)(1) and (2) of this section is optional. That is, the owner or operator may choose to apply a NO_x allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

[New §60.332(a)(3) added at 69 FR 41359, July 8, 2004]

(4) If the owner or operator elects to apply a NO_x emission allowance for fuel-bound nitrogen, F shall be

defined according to the nitrogen content of the fuel during the most recent performance test required under §60.8 as follows:

Fuel-bound nitrogen (percent by weight)	F (NO _x percent by volume)
N ≤ 0.015.....	0
0.015 < N ≤ 0.1	0.04 (N)
0.1 < N ≤ 0.25.....	0.004 + 0.0067 (N-0.1)
N > 0.25.....	0.005

Where:

N = the nitrogen content of the fuel (percent by weight).

or:

Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by §60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the **Federal Register**.

[Former §60.332(a)(3) amended and redesignated as new (4) at 68 FR 17998, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; redesignated as new (4) and amended at 69 FR 41360, July 8, 2004]

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in §60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_x emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, FEDERAL REGISTER (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

40 CFR 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by §60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any

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fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

[§60.333(b) amended at 68 FR 17998, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; amended at 69 FR 41360, July 8, 2004]

40 CFR 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_x emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

[§60.334(a) revised at 68 FR 17998, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; revised at 69 FR 41360, July 8, 2004]

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_x emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_x and O₂ monitors. As an alternative, a CO₂ monitor may be used to adjust the measured NO_x concentrations to 15 percent O₂ by either converting the CO₂ hourly averages to equivalent O₂ concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O₂, or by using the CO₂ readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_x and diluent monitors may be performed individually or on a combined basis, *i.e.*, the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_x) and a percent O₂ basis for oxygen; or

(ii) On a ppm at 15 percent O₂ basis; or

(iii) On a ppm basis (for NO_x) and a percent CO₂ basis (for a CO₂ monitor that uses the procedures in Method 20 to correct the NO_x data to 15 percent O₂).

(2) As specified in §60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum

of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in §60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_x and diluent, the data acquisition and handling system must calculate and record the hourly NO_x emissions in the units of the applicable NO_x emission standard under §60.332(a), *i.e.*, percent NO_x by volume, dry basis, corrected to 15 percent O₂ and International Organization for Standardization (ISO) standard conditions (if required as given in §60.335(b)(1)). For any hour in which the hourly average O₂ concentration exceeds 19.0 percent O₂, a diluent cap value of 19.0 percent O₂ may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (H_o), minimum ambient temperature (T_a), and minimum combustor inlet absolute pressure (P_o) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_x CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in §60.7(c).

[§60.334(b) revised at 68 FR 17998, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; revised at 69 FR 41360, July 8, 2004]

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_x emissions, the owner or operator may, but is not required to, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA, State, or local permitting authority approval of a procedure for monitoring compliance with the applicable NO_x emission limit under §60.332, that approved procedure may continue to be used.

[New §60.334(c) added at 69 FR 41360, July 8, 2004; amended at 71 FR 9457, Feb. 24, 2006, effective April 25, 2006]

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam

injection to control NO_x emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_x CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

[§60.334(d) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004]

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_x emissions, may, but is not required to, elect to use a NO_x CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. Other acceptable monitoring approaches include periodic testing approved by EPA or the State or local permitting authority or continuous parameter monitoring as described in paragraph (f) of this section.

[§60.334(e) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004; amended at 71 FR 9457, Feb. 24, 2006, effective April 25, 2006]

(f) The owner or operator of a new turbine that commences construction after July 8, 2004, which does not use water or steam injection to control NO_x emissions may, but is not required to, perform continuous parameter monitoring as follows:

[§60.334(f) introductory text amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_x formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_x mode.

[§60.334(f)(2) amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

(3) For any turbine that uses SCR to reduce NO_x emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_x emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19 of this chapter, the requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in §75.19(c)(1)(iv)(H) of this chapter.

[§60.334(f) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004]

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under §60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in §75.19 of this chapter or the NO_x emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in §75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

[§60.334(g) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004]

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in §60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228- 98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see §60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (*i.e.*, if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in §60.332). The nitrogen content of the fuel shall be determined using methods described in §60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of

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appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

[§60.334(h) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004]

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) *Gaseous fuel.* Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) *Custom schedules.* Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

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(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (*i.e.*, the maximum total sulfur content of natural gas as defined in §60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

[§60.334(i) added at 68 FR 17999, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41361, July 8, 2004]

(j) For each affected unit that elects to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

[Former §60.334(c) redesignated as new (j) and former (c) introductory text redesignated and revised as new (j) introductory text at 68 FR 18000, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; redesignated and revised as new (j) at 69 FR 41361, July 8, 2004; (j) introductory text amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with §60.332, as established during the performance test required in §60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in §60.8 and used to determine the allowance. The excess emission begins on the date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of

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monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_x and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds the applicable emission limit in §60.332(a)(1) or (2). For the purposes of this subpart, a "4-hour rolling average NO_x concentration" is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15 percent O₂ and, if required under §60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in §60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of §60.335(b)(1).

(iv) For owners or operators that elect, under paragraph (f) of this section, to monitor combustion parameters or parameters that document proper operation of the NO_x emission controls:

[§60.334(j)(1)(iv) introductory text amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

[Former §60.334(c)(1) revised and redesignated as new (j)(1) at 68 FR 18000, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; redesignated and revised as new (j)(1) at 69 FR 41362, July 8, 2004]

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (*i.e.*, daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

[Former §60.334(c)(2) revised and redesignated as new (j)(2) at 68 FR 18001, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; redesignated and revised as new (j)(2) at 69 FR 41363, July 8, 2004]

(3) *Ice fog*. Each period during which an exemption provided in §60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

[Former §60.334(c)(3) amended at 65 FR 61759, Oct. 17, 2000; redesignated as new (j)(3) at 68 FR 17998, April 14, 2003; withdrawn and former text restored at 68 FR 31611, May 28, 2003; redesignated and revised as new (j)(3) at 69 FR 41360, July 8, 2004]

(4) *Emergency fuel*. Each period during which an exemption provided in §60.332(k) is in effect shall be included in the report required in §60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under §60.7(c) shall be postmarked by the 30th day following the end of each 6-month period.

[§60.334(j)(5) added at 68 FR 18001, April 14, 2003; withdrawn at 68 FR 31611, May 28, 2003; added at 69 FR 41363, July 8, 2004; amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

40 CFR 60.335 Test methods and procedures.

[§60.335 revised at 69 FR 41363, July 8, 2004]

(a) The owner or operator shall conduct the performance tests required in §60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see §60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_x and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_x and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O₂, is within ± 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_x concentration during the stratification test; or

(B) If each of the individual traverse point NO_x concentrations, normalized to 15 percent O₂, is within ± 5

percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in §60.332 and shall meet the performance test requirements of §60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{XO}) corrected to 15 percent O_2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$\text{NO}_\text{X} = (\text{NO}_{\text{XO}})(P_r/P_o)^{0.5} e^{19(H_o-0.00633)} (288^\circ\text{K}/T_a)^{1.53}$$

Where:

NO_X = emission concentration of NO_X at 15 percent O_2 and ISO standard ambient conditions, ppm by volume, dry basis,

NO_{XO} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O_2 ,

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,

P_o = observed combustor inlet absolute pressure at test, mm Hg,

H_o = observed humidity of ambient air, g H_2O /g air,

e = transcendental constant, 2.718, and

T_a = ambient temperature, $^\circ\text{K}$.

(2) The 3-run performance test required by §60.8 must be performed within ± 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding these requirements, performance testing is not required for any emergency fuel (as defined in §60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in §60.332 for the combustion turbine must still be met.

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(4) If water or steam injection is used to control NO_x with no additional post-combustion NO_x control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with §60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see §60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable §60.332 NO_x emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in §60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in §60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_x CEMS under §60.334(e), then the initial performance test required under §60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_x emission limit under §60.332 and to provide the required reference method data for the RATA of the CEMS described under §60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator elects under §60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_x emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in §60.334(g).

[§60.335(b)(8) amended at 71 FR 9458, Feb. 24, 2006, effective April 25, 2006]

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under §60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, *see* §60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, *see* §60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in §60.8 to ISO standard day conditions.

40 CFR 60.336 [Removed]

[§60.336 added at 58 FR 18015, April 7, 1993; removed at 58 FR 34370, June 25, 1993]

COMMONWEALTH OF VIRGINIA
Department of Environmental Quality



AIR PERMIT APPLICATION

General Information

CHECK ALL FORMS THAT APPLY AND LIST ALL ATTACHED DOCUMENTS.

MAP AND LOCALITIES LIST (information), Pages iii-v

CONFIDENTIAL INFORMATION, Page vi-viii

FORMULA-BASED HAZARDOUS AIR POLLUTANT INFORMATION, Page ix

HAZARDOUS AIR POLLUTANT LIST (information), Pages xi-xii

REQUEST FOR LOCAL GOVERNMENT CERTIFICATION FORM, Page xii

1 CONTENTS AND DOCUMENT CERTIFICATION, Page 1

1 GENERAL INFORMATION, Page 2

1 GENERAL INFORMATION (continued), Page 3

___ FUEL-BURNING EQUIPMENT, Page 4

___ PROCESSING, Page 5

___ INKS, COATINGS, STAINS, AND ADHESIVES, Page 6

___ INCINERATORS, Page 7

___ VOLATILE ORGANIC COMPOUND/PETROLEUM STORAGE TANKS, Page 8

___ VOLATILE ORGANIC COMPOUND/PETROLEUM STORAGE TANKS -
CONTINUED, Page 9

___ LOADING RACKS AND OIL-WATER SEPARATORS, Page 10

___ STACK PARAMETERS AND FUEL DATA, Page 11

___ AIR POLLUTION CONTROL AND MONITORING EQUIPMENT, PAGE 12

___ AIR POLLUTION CONTROL SUPPLEMENTAL INFORMATION, PAGE 13

___ PROPOSED MAXIMUM CRITERIA POLLUTANT EMISSIONS, Page 14

___ PAST ACTUAL ANNUAL CRITERIA POLLUTANT EMISSIONS, Page 15

___ TOXIC OR HAP EMISSIONS, Page 16

___ OTHER REGULATED EMISSIONS, Page 17

___ OPERATING PERIODS, Page 18

LIST ATTACHED DOCUMENTS

___ MAP of SITE LOCATION

___ FACILITY SITE PLAN

___ PROCESS FLOW DIAGRAM/SCHEMATIC

___ MSDS or CPDS SHEETS

___ ESTIMATED EMISSIONS CALCULATIONS

___ STACK TESTS

___ AIR MODEL DATA

1 CAIR Permit Application

3 Certificate of Representation

Note added form sheets above; also indicate the number of copies of each form in blank provided.

DOCUMENT CERTIFICATION FORM
(see other side for instructions)

I certify under penalty of law that this document and all attachments [as noted above] were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering and evaluating the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

I certify that I understand that the existence of a permit under [Article 6 of the Regulations] does not shield the source from potential enforcement of any regulation of the board governing the major NSR program and does not relieve the source of the responsibility to comply with any applicable provision of the major NSR regulations.

SIGNATURE: _____

DATE: 14 JUN 07

NAME: Robert L. Greene

TITLE: Plant Manager/Director

COMPANY: Hopewell Cogeneration Facility

REGISTRATION

50967

NUMBER: _____

References: Virginia Regulations for the Control and Abatement of Air Pollution (Regulations), 9 VAC 5-20-230B and 9 VAC 5-80-1140E. See reverse of this form for instructions.

COMMONWEALTH OF VIRGINIA
DEPARTMENT OF ENVIRONMENTAL QUALITY

DOCUMENT CERTIFICATION FORM

INSTRUCTIONS FOR USE

Various provisions of the Regulations for the Control and Abatement of Air Pollution require that certain documents submitted to the Board or the Department be signed by a responsible official with certification that the information contained in the statement is accurate to the best knowledge of the individual certifying the statement. Documents covered by this requirement include, but are not limited to, permit applications, registrations, emission statements, emission testing and monitoring reports, or compliance certifications. The certification should include the full name, title, signature, date of signature, and telephone number of the responsible official. A responsible official is defined as follows (Regulations, 9 VAC 5-20-230A.):

- a. For a business entity, such as a corporation, association or cooperative, a responsible official is either:
 - (1) The president, secretary, treasurer, or a vice-president of the business entity in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the business entity, or
 - (2) A duly authorized representative of such business entity if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either (i) the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars), or (ii) the authority to sign documents has been assigned or delegated to such representative in accordance with procedures of the business entity.
- b. For a partnership or sole proprietorship, a responsible official is a general partner or the proprietor, respectively.
- c. For a municipality, state, federal, or other public agency, a responsible official is either a principal executive officer or ranking elected official. A principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency.

Certification is required with each application submittal, including amendments to an application (i.e. new pages, revisions to existing pages and other amendments to application information).

Reference: Regulations, 9 VAC 5-80-1140D. Letters, phone calls, etc. are considered additional supplementary information to the certified application submittal.

COMMONWEALTH OF VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR PERMIT APPLICATION GENERAL INFORMATION

PERSON COMPLETING FORM	DATE	REGISTRATION NUMBER
Chuck Barnes	13 June 2007	50967

REASON(S) FOR SUBMISSION (Check all that apply):

☐ STATE OPERATING PERMIT

THIS PERMIT IS APPLIED FOR PURSUANT TO PROVISIONS OF THE VIRGINIA ADMINISTRATIVE CODE, 9 VAC 5 Chapter 80, Article 5 (SOP)

☐ NEW (Greenfield) SOURCE

THIS PERMIT IS APPLIED FOR PURSUANT TO THE FOLLOWING PROVISION(S) OF THE VIRGINIA ADMINISTRATIVE CODE:

☐ MODIFICATION of a SOURCE

☐ 9 VAC 5 Chapter 80, Art. 6 (MINOR SOURCES)

☐ RELOCATION of a SOURCE

☐ 9 VAC 5 Chapter 80, Art. 8 (PSD MAJOR SOURCES)

☐ 9 VAC 5 Chapter 80, Art. 9 (NON-ATTAINMENT MAJOR SOURCES)

☐ Non-Binding Letter of EXEMPTION

☒ AMENDMENT to a Permit dated: _____ Permit type: ☐ SOP (Art. 5) ☐ NSR (Art. 6)

Amendment Type:

☐ Administrative Amendment

☐ Minor Amendment

☐ Significant Amendment

THIS AMENDMENT IS REQUESTED PURSUANT TO THE PROVISIONS OF:

☐ 9 VAC 5-80-970 (SOP Adm.)

☐ 9 VAC 5-80-1270 (NSR Adm.)

☐ 9 VAC 5-80-980 (SOP Minor)

☐ 9 VAC 5-80-1280 (NSR Minor)

☐ 9 VAC 5-80-990 (SOP Sig.)

☐ 9 VAC 5-80-1290 (NSR. Sig.)

Complete Pages 1, 2, and 3 and refer to the above checked provisions for additional information requirements. Form 7 pages may be used to satisfy those requirements.

☐ Notification of Change in Ownership - Effective Date: _____

☐ Notification of Facility Name Change - Effective Date: _____

☐ Notification of Owner Name Change - Effective Date: _____

☒ Other (Specify): **Add CAIR Requirements to the present permit**

COMPANY AND DIVISION NAME:

Hopewell Cogeneration Facility

MAILING ADDRESS:

1114 Hercules Road, Hopewell, Virginia 23860

TELEPHONE

(804) 458-0700

NUMBER OF EMPLOYEES AT SITE:

20

PROPERTY AREA AT SITE:

6 Acres

EXACT SOURCE LOCATION - INCLUDE NAME OF CITY (COUNTY) AND FULL STREET ADDRESS OR DIRECTIONS:

1114 Hercules Road, Hopewell, Virginia 23860

PERSON TO CONTACT ON AIR POLLUTION MATTERS - NAME AND TITLE:

Chuck Barnes

Plant Engineer

PHONE NUMBER: **(804) 458-0700**

FAX NUMBER: **(804) 458-0794**

E-MAIL ADDRESS:

chuck.barnes@suezenergyna.com

☐ Please check here if you obtained this form from the DEQ website.

FOR OFFICIAL USE ONLY

COUNTY CODE:

PLANT ID NUMBER:

LAT/LONG:

GENERAL INFORMATION INSTRUCTIONS

REASON FOR SUBMISSION - check the appropriate box(es) and the applicable regulation(s).

1. "STATE OPERATING PERMIT" means that you are either an existing source applying for an operating permit, or are a NEW (Greenfield) SOURCE applying for a State Operating Permit concurrently with a permit to construct and operate the NEW (Greenfield) SOURCE. State Operating Permits are normally optional, and are requested for one of the reasons stated in 9 VAC 5-80-800 C.
2. "NEW (Greenfield) SOURCE" means that you are either constructing emission units at a new facility where no facility now exists, or you are constructing emission units at a facility that previously had no emission units at the facility. The NEW (Greenfield) SOURCE is (or may be) subject to permit review requirements.
3. "MODIFICATION of a SOURCE" means that (1) you already have emission units at your facility, (2) you are making physical or operational changes to the facility, (3) those proposed changes could result in a net emission increase of a regulated pollutant (or the emission of a regulated pollutant not presently being emitted), and (4) that physical or operational change is (or may be) subject to permit review requirements.
4. "RELOCATION of a SOURCE" means that you are relocating emission units from a facility in one location to a new or existing facility in another location, and that relocation is (or may be) subject to permit review.
5. "Non-Binding Letter of EXEMPTION" means that you are applying for written confirmation that a particular change is not subject to permit review under 9 VAC 5, Chapter 80, Articles 6, 8, or 9.
6. "PERMIT AMENDMENT" means that you have an effective air permit for your source, and you need changes made to that permit that do not qualify as a "MODIFICATION of a SOURCE".
7. "REGISTRATION/REGISTRATION UPDATE" means that you are applying to register a source that is not otherwise subject to permit review under 9 VAC 5, Chapter 80, Articles 6, 8 or 9, or you are applying to update a previous registration. See 9 VAC 5-20-160 of the regulations.
8. "NOTIFICATION OF CHANGE IN OWNERSHIP" means that you simply are notifying DEQ of the changes as required by regulation.
9. "NOTIFICATION OF FACILITY NAME CHANGE" means that you simply are notifying DEQ of the changes as required by regulation.
10. "NOTIFICATION OF OWNER NAME CHANGE" means that you simply are notifying DEQ of the changes as required by regulation.
11. "OTHER (SPECIFY)" means you intend to make a change to your facility, you do not know what air permitting requirements apply, and you wish for DEQ to evaluate the change for you and determine which requirements apply. Fill out the Form 7 as completely as possible and describe in a letter what you wish to do.

The listed regulations detail the various types of air pollution permits. Please indicate which of these you believe are applicable to this application. (More than one may apply). Sections of the regulations may be downloaded from the DEQ web site at <http://www.deq.state.va.us/>. Copies of the regulations are available for purchase from the WestGroup by calling 1-800-326-4880 (Air regulations are contained in Volume 6, Title 9 of the Virginia Administrative Code).

COMPANY AND DIVISION NAME - list the official company name and the division if applicable.

MAILING ADDRESS - list the mailing address that corresponds to the facility on this application.

TELEPHONE NUMBER - list the phone number at the facility.

NUMBER OF EMPLOYEES AT SITE - list the number of employees at the facility.

PROPERTY AREA AT SITE - list the area in acres.

EXACT SOURCE LOCATION - provide a description of the facility location indicating street address or directions to facility; provide a map pinpointing the exact source location and specify where the plant property boundaries are, if requested by the regional office; provide a plant layout with dimensions of all buildings (height, length, width) at the facility indicating all stack and emission point locations by stack or reference number, if requested.

PERSON TO CONTACT ON AIR POLLUTION MATTERS - provide the name/title of a contact person for air pollution matters.

PHONE NUMBER - provide a phone number at which DEQ staff can reach the contact person.

FAX PHONE NUMBER - provide the fax number of the contact person, if there is one.

E-MAIL ADDRESS - provide an E-mail address of the contact person, if you wish to communicate with DEQ by e-mail.

FOR OFFICIAL USE ONLY - provided for use by the DEQ regional office.

AIR PERMIT APPLICATION GENERAL INFORMATION (continued)

COMPANY NAME	DATE	REGISTRATION NUMBER
Hopewell Cogeneration Facility	13 June 2007	50967

FOR PORTABLE PLANTS:

IS THIS FACILITY DESIGNED TO BE PORTABLE? ☐ YES ☐ NO

- IF YES, IS THIS FACILITY ALREADY PERMITTED AS A PORTABLE PLANT? ☐ YES ☐ NO PERMIT DATE: _____

IF NOT PERMITTED, IS THIS AN APPLICATION TO BE PERMITTED AS A PORTABLE PLANT? ☐ YES ☐ NO

IF PERMITTED AS A PORTABLE FACILITY, IS THIS A NOTIFICATION OF RELOCATION? ☐ YES ☐ NO

- DESCRIBE THE NEW LOCATION OR ADDRESS (INCLUDE A SITE MAP): _____

- WILL THE PORTABLE FACILITY BE CO-LOCATED WITH ANOTHER SOURCE? ☐ YES ☐ NO REG. NO.: _____

- WILL THE PORTABLE FACILITY BE MODIFIED OR RECONSTRUCTED AS A RESULT OF THE RELOCATION? ☐ YES ☐ NO

- WILL THERE BE ANY NEW EMISSIONS OTHER THAN THOSE ASSOCIATED WITH THE RELOCATION? ☐ YES ☐ NO

- IS THE FACILITY SUITABLE FOR THE AREA TO WHICH IT WILL BE LOCATED? (ATTACH DOCUMENTATION.) ☐ YES ☐ NO

DESCRIBE THE PRODUCTS MANUFACTURED AND/OR SERVICES PERFORMED AT THIS FACILITY:

This plant produces Electrical Power for Dominion Virginia Power, and Steam for Hercules Chemical Company.

LIST THE STANDARD INDUSTRIAL CLASSIFICATION (SIC) CODE(S) FOR THE FACILITY:

[illegible]

LIST THE NORTH AMERICAN INDUSTRY CLASSIFICATION SYSTEM (NAICS) CODE(S) FOR THE FACILITY:

2	2	1	1	1	9	2	2	1	3	3	0						
---	---	---	---	---	---	---	---	---	---	---	---	--	--	--	--	--	--

PLEASE LIST ALL THE FACILITIES IN VIRGINIA UNDER COMMON OWNERSHIP OR CONTROL BY THE OWNER OF THIS FACILITY:

MILESTONES. This section is to be completed if the permit application includes a new emissions unit or modification to existing operations.

<div>MILESTONES*</div>	<div>STARTING DATE</div>	<div>ESTIMATED COMPLETION DATE</div>
New equipment installation		
Modification of existing process or equipment		
Start-up dates		

*For new or modified installations to be constructed in phased schedule, give construction/installation starting and completion date for each phase.

GENERAL INFORMATION (continued) INSTRUCTIONS

COMPANY NAME - give the company name, the date completed, and the registration number assigned to the facility if applicable.

IS THE FACILITY DESIGNED TO BE PORTABLE? - 9 VAC 5-80-1110 B defines "portable", to mean an emissions unit that is designed to have the capability of being moved from one location to another for the purpose of operating at multiple locations and storage when idle. Indications of portability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform. If this facility is already permitted as a portable facility, list the date of the effective permit.

IS THIS AN APPLICATION TO BE PERMITTED AS A PORTABLE PLANT? - if the facility is designed to be portable, indicate whether or not you wish to have the permit contain specific conditions that will acknowledge this fact, so that the facility may be relocated without a new permit in accordance with 9 VAC 5-80-1320 A.1.c.

IS THIS A NOTIFICATION OF RELOCATION OF A PORTABLE FACILITY? - 9 VAC 5-80-1320 A.1.c allows the relocation of a properly permitted portable facility to be exempt from permitting requirements, as long as it meets certain requirements, one of which is timely notification of the relocation. This notification should be sent to the Director of the DEQ Regional Office into whose area of responsibility the facility will be relocated. The 15-day notification period begins when DEQ receives the notification. Submission of pages 1, 2, and 3 of this form 7 may be used for that notification (with "RELOCATION of a SOURCE" marked on Page 2). However, use of this form for that purpose is not required. Note that a site map and documentation of site suitability should accompany this form or whatever means of notification is used. Include the registration number of any stationary source that will be co-located with the portable facility at the new site.

Site suitability may be documented by the use of a properly certified Local Governing Body Certification Form from the locality to which the facility will be relocated, although that form is not required for this purpose. Contact the appropriate DEQ Regional Office for instructions. DEQ will make a determination of site suitability based upon regional and local requirements.

PRODUCTS MANUFACTURED/SERVICED - indicate the type of business in which this facility is engaged, listing products produced and/or services performed.

SIC CODE(S) - provide all 4-digit Standard Industrial Classification Code(s) for this facility and for the process(es). Place primary SIC in the first set of blocks.

NAICS CODE(S) - provide all 6-digit North American Industry Classification System Code(s) for this facility and for the process(es). Place primary NAICS in the first set of blocks.

FACILITIES UNDER COMMON OWNERSHIP - list the facilities in Virginia that are owned by the applicant company, its subsidiaries, and its parent company.

MILESTONE DATES - list all dates pertinent to this application as accurately as possible. For start-up dates, provide each relevant date as it might affect emissions, e.g., start-up of each unit, modification of each unit, imposition of or changes in permitted emissions for each unit.

CAIR Permit Application

(for sources covered under a CAIR SIP)

Page 1

For more information, refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321, and 96.322

This submission is: ☒ New ☐ Revised

STEP 1
Identify the source by plant name, State, and ORIS or facility code

Hopewell Cogeneration Facility	Virginia	10633
Plant Name	State	ORIS/Facility Code

STEP 2
Enter the unit ID# for each CAIR unit and indicate to which CAIR programs each unit is subject (by placing an "X" in the column)

Unit ID#	NO _x Annual	SO ₂	NO _x Ozone Season
ID#1 (Gas Turbine #1)	X	X	X
ID#2 (Gas Turbine #2)	X	X	X
ID#3 (Gas Turbine #3)	X	X	X

STEP 3
Read the standard requirements and the certification, enter the name of the CAIR designated representative, and sign and date

Standard Requirements

(a) Permit Requirements.

(1) The CAIR designated representative of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under §96.122, §96.222, and §96.322 (as applicable) in accordance with the deadlines specified in §96.121, §96.221, and §96.321 (as applicable); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) required to have a title V operating permit and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II, III, and IIII (as applicable) of 40 CFR part 96, the owners and operators of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) that is not otherwise required to have a title V operating permit and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC, CCC, and CCCC (as applicable) of 40 CFR part 96 for such CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) and such CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable).

Hopewell Cogeneration Facility

Plant Name (from Step 1)

CAIR Permit Application
Page 2

STEP 3, continued

(b) Monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(2) The emissions measurements recorded and reported in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 shall be used to determine compliance by each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) with the CAIR NO_x emissions limitation, CAIR SO₂ emissions limitation, and CAIR NO_x Ozone Season emissions limitation (as applicable) under paragraph (c) of §96.106, §96.206, and §96.306 (as applicable).

(c) Nitrogen oxides emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x source and each CAIR NO_x unit at the source shall hold, in the source's compliance account, CAIR NO_x allowances available for compliance deductions for the control period under §96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x units at the source, as determined in accordance with subpart HH of 40 CFR part 96.

(2) A CAIR NO_x unit shall be subject to the requirements under paragraph (c)(1) of §96.106 for the control period starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.170(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR NO_x allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.106, for a control period in a calendar year before the year for which the CAIR NO_x allowance was allocated.

(4) CAIR NO_x allowances shall be held in, deducted from, or transferred into or among CAIR NO_x Allowance Tracking System accounts in accordance with subparts FF, GG, and II of 40 CFR part 96.

(5) A CAIR NO_x allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Annual Trading Program. No provision of the CAIR NO_x Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_x allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EE, FF, GG, or II of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_x allowance to or from a CAIR NO_x source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_x unit.

Sulfur dioxide emission requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO₂ source and each CAIR SO₂ unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO₂ allowances available for compliance deductions for the control period under §96.254(a) and (b) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO₂ units at the source, as determined in accordance with subpart HHH of 40 CFR part 96.

(2) A CAIR SO₂ unit shall be subject to the requirements under paragraph (c)(1) of §96.206 for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §96.270(b)(1), (2), or (5) and for each control period thereafter.

(3) A CAIR SO₂ allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.206, for a control period in a calendar year before the year for which the CAIR SO₂ allowance was allocated.

(4) CAIR SO₂ allowances shall be held in, deducted from, or transferred into or among CAIR SO₂ Allowance Tracking System accounts in accordance with subparts FFF, GGG, and III of 40 CFR part 96.

(5) A CAIR SO₂ allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO₂ Trading Program. No provision of the CAIR SO₂ Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR SO₂ allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FF, FFF, GGG, or III of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR SO₂ allowance to or from a CAIR SO₂ source's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO₂ unit.

Nitrogen oxides ozone season emissions requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_x Ozone Season allowances available for compliance deductions for the control period under §96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x Ozone Season units at the source, as determined in accordance with subpart HHHH of 40 CFR part 96.

(2) A CAIR NO_x Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of §96.306 for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under §96.370(b)(1), (2), (3) or (7) and for each control period thereafter.

(3) A CAIR NO_x Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of §96.306, for a control period in a calendar year before the year for which the CAIR NO_x Ozone Season allowance was allocated.

(4) CAIR NO_x Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_x Ozone Season Allowance Tracking System accounts in accordance with subparts FFFF, GGGG, and IIII of 40 CFR part 96.

(5) A CAIR NO_x Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Ozone Season Trading Program. No provision of the CAIR NO_x Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under §96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_x Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart EEEE, FFFF, GGGG, or IIII of 40 CFR part 96, every allocation, transfer, or deduction of a CAIR NO_x Ozone Season allowance to or from a CAIR NO_x Ozone Season source's compliance account is incorporated automatically in any CAIR permit of the source.

Hopewell Cogeneration Facility

Plan: Name (from Step 1)

CAIR Permit Application
Page 3

STEP 3,
continued

(d) Excess emissions requirements.

If a CAIR NO_x source emits nitrogen oxides during any control period in excess of the CAIR NO_x emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO_x unit at the source shall surrender the CAIR NO_x allowances required for deduction under §96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR SO₂ source emits sulfur dioxide during any control period in excess of the CAIR SO₂ emissions limitation, then:

(1) The owners and operators of the source and each CAIR SO₂ unit at the source shall surrender the CAIR SO₂ allowances required for deduction under §96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

If a CAIR NO_x Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_x Ozone Season emissions limitation, then:

(1) The owners and operators of the source and each CAIR NO_x Ozone Season unit at the source shall surrender the CAIR NO_x Ozone Season allowances required for deduction under §96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(e) Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §96.113, §96.213, and §96.313 (as applicable) for the CAIR designated representative for the source and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §96.113, §96.213, and §96.313 (as applicable) changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96, provided that to the extent that subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable).

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable) or to demonstrate compliance with the requirements of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable).

(2) The CAIR designated representative of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) and each CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) at the source shall submit the reports required under the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable) including those under subparts HH, HHH, and HHHH (as applicable) of 40 CFR part 96.

(f) Liability.

(1) Each CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) and each NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) shall meet the requirements of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable).

(2) Any provision of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable) that applies to a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) or the CAIR designated representative of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) shall also apply to the owners and operators of such source and of the CAIR NO_x units, CAIR SO₂ units, and CAIR NO_x Ozone Season units (as applicable) at the source.

(3) Any provision of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable) that applies to a CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) or the CAIR designated representative of a CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable); shall also apply to the owners and operators of such unit.

Plant Name (from Step 1)

Hopewell Cogeneration Facility

CAIR Permit Application
Page 4

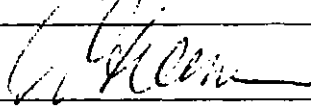
STEP 3,
continued

(g) Effect on Other Authorities

No provision of the CAIR NO_x Annual Trading Program, CAIR SO₂ Trading Program, and CAIR NO_x Ozone Season Trading Program (as applicable), a CAIR permit application, a CAIR permit, or an exemption under § 96.105, §96.205, and §96.305 (as applicable) shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x source, CAIR SO₂ source, and CAIR NO_x Ozone Season source (as applicable) or CAIR NO_x unit, CAIR SO₂ unit, and CAIR NO_x Ozone Season unit (as applicable) from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Certification

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Robert L. Greene	
Signature 	Date 19 June 07



Certificate of Representation

Page 1

For more information, see instructions and 40 CFR 72.24, 40 CFR 96.113, 96.213, or 97.213, or a comparable state regulation under the Clean Air Interstate Rule (CAIR) NO_x Annex, SO₂ Annex, and NO_x Ozone Season Trading Programs, or 40 CFR 97.113, 97.213, or 97.313, as applicable.

This submission is: ☒ New ☐ Revised (revised submissions must be complete; see instructions)

FACILITY (SOURCE) INFORMATION

STEP 1
Provide information for the facility (source).

Hopewell Cogeneration Facility Facility (Source) Name	Virginia State	10633 Plant Code
Independent City of Hopewell in the County of Prince George Virginia County Name		
N 37° 17' 30" Latitude	W 77° 16' 50" Longitude	

STEP 2
Enter requested information for the designated representative.

Robert L. Greene Name	Plant Manager Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>Bob.Greene@suezenergyna.com</u> E-mail address	

STEP 3
Enter requested information for the alternate designated representative.

Chuck Barnes Name	Plant Engineer Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>chuck.barnes@suezenergyna.com</u> E-mail address	

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Page 1 of 3

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NOx Annual X CAIR SO₂ ~ CAIR NOx Ozone Season

ORIS-10633 DEQ-50967 ID# 1	CC Combined Cycle Unit Type	Source Category Cogeneration	Generator ID Number ID# 1	Acid Rain Nameplate Capacity (MW)	CAIR Nameplate Capacity (MW)
Unit ID#	NAICS Code 221119				89 MW
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): 08/01/1990		Check One: Actual X Projected ~			
Hopewell Cogeneration Facility					
Company Name: ~ Owner X Operator					
Suez Energy Generation NA					
Company Name: X Owner Operator					
Company Name: ~ Owner Operator					
Company Name: ~ Owner Operator					
Company Name: ~ Owner Operator					
Company Name: ~ Owner Operator					

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_x Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NO_x Annual ☒ CAIR SO₂ ~ CAIR NO_x Ozone Season

ORIS-10633 DEQ-50967 ID# 2	CC Combined Cycle Unit Type	Source Category Cogeneration	NAICS Code 221119	Generator ID Number ID# 2	Acid Rain Nameplate Capacity (MW)	CAIR Nameplate Capacity (MW)
Unit ID#	08/01/1990	Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):		Check One: Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>		
Company Name:	Hopewell Cogeneration Facility			~ Owner <input checked="" type="checkbox"/> Operator		
Company Name:	Suez Energy Generation NA			<input checked="" type="checkbox"/> Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		

COPY

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NOx Annual ☒ CAIR SO₂ ~ CAIR NOx Ozone Season

ORIS-10633 DEQ-50967 ID# 3	CC Combined Cycle Unit Type	Source Category Cogeneration	Generator ID Number ID# 3	Acid Rain Nameplate Capacity (MW _{pe})	CAIR Nameplate Capacity (MW _{pe})
Unit ID#	NAICS Code 221119	Check One: Actual <input checked="" type="checkbox"/> Projected ~			89 MW
Date unit began (or will begin) serving any generator producing electricity for sale (mm/dd/yyyy): 08/01/1990					
Hopewell Cogeneration Facility					
Company Name: ~ Owner X Operator					
Suez Energy Generation NA					
Company Name: X Owner ~ Operator					
Company Name: ~ Owner ~ Operator					
Company Name: ~ Owner ~ Operator					
Company Name: ~ Owner ~ Operator					
Company Name: ~ Owner ~ Operator					

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 3

STEP 5: Read the certifications, sign and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in ~~Applicable~~ Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and

Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source (i.e., the source and each unit subject to the CAIR NO_x Annual Trading Program, as indicated in ~~Applicable~~ Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Annual Trading Program on behalf of the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x unit, or where a utility or industrial customer purchases power from a CAIR NO_x unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x source and each CAIR NO_x unit at the source; and

CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x allowances by contract, CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 4

Clean Air Interstate Rule (CAIR) SO₂ Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source (i.e., the source and each unit subject to the SO₂ Trading Program, as indicated in Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO₂ Trading Program, on behalf of the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO₂ unit, or where a utility or industrial customer purchases power from a CAIR SO₂ unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO₂ source and each CAIR SO₂ unit at the source; and

CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO₂ allowances by contract, CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_x Ozone Season Trading Program, as indicated in Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Ozone Season Trading Program on behalf of the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_x Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit; and

CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x Ozone Season allowances by contract, CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 5

COPY

General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

 Signature (Designated Representative)	Date 16 MAY 2007
 Signature (Alternate Designated Representative)	Date 13 June 2007



Certificate of Representation

Page 1

For more information, see instructions and 40 CFR 72.24, 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR), NO_x Annual, SO₂ and NO_x Ozone Season Trading Programs, or 40 CFR 97.113, 97.213, or 97.313, as applicable.

This submission is: ☒ New ☐ Revised (revised submissions must be complete; see instructions)

FACILITY (SOURCE) INFORMATION

STEP 1
Provide information for the facility (source).

Hopewell Cogeneration Facility Facility (Source) Name	Virginia State	10633 Plant Code
Independent City of Hopewell in the County of Prince George Virginia County Name		
N 37° 17' 30" Latitude	W 77° 16' 50" Longitude	

STEP 2
Enter requested information for the designated representative.

Robert L. Greene Name	Plant Manager Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>Bob.Greene@suezenergyna.com</u> E-mail address	

STEP 3
Enter requested information for the alternate designated representative.

Chuck Barnes Name	Plant Engineer Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>chuck.barnes@suezenergyna.com</u> E-mail address	

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain
X CAIR NO_x Annual ~ CAIR SO₂
 ~ CAIR NO_x Ozone Season

ORIS-10633 DEQ-50967 ID# 1	CC Combined Cycle Unit Type	Source Category Cogeneration	NAICS Code 221119	Generator ID Number ID# 1	Acid Rain Nameplate Capacity (MW _{ac})	CAIR Nameplate Capacity (MW _{ac}) 89 MW
08/01/1990		Check One: Actual X Projected ~				
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):						
Hopewell Cogeneration Facility				~ Owner X Operator		
Suez Energy Generation NA				X Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		
Company Name:				~ Owner ~ Operator		

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ☒ CAIR NOx Annual ☒ CAIR SO₂ ☒ CAIR NOx Ozone Season

Generator ID Number	Acid Rain Nameplate Capacity (MW)	CAIR Nameplate Capacity (MW)				
ID# 2		89 MW				
<table border="1"> <thead> <tr> <th>Source Category</th> <th>Cogeneration</th> </tr> </thead> <tbody> <tr> <td>NAICS Code</td> <td>221119</td> </tr> </tbody> </table>			Source Category	Cogeneration	NAICS Code	221119
Source Category	Cogeneration					
NAICS Code	221119					
<table border="1"> <thead> <tr> <th>Unit Type</th> <th>Check One:</th> </tr> </thead> <tbody> <tr> <td>CC Combined Cycle</td> <td>Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/></td> </tr> </tbody> </table>			Unit Type	Check One:	CC Combined Cycle	Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>
Unit Type	Check One:					
CC Combined Cycle	Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>					
Date unit began (or will begin) serving any generator producing electricity for sale (month/yyyy): 08/01/1990						
Hopewell Cogeneration Facility						
Suez Energy Generation NA						
Company Name:						
Company Name:						
Company Name:						
Company Name:						
Company Name:						
Company Name:						

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Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Page 3 of 3

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ☒ CAIR NOx Annual ~ CAIR SO₂ ~ CAIR NOx Ozone Season

ORIS-10633 DEQ-50967 ID# 3	CC Combined Cycle	Source Category	Cogeneration		Generator ID Number ID# 3	Acid Rain Nameplate Capacity (MWel)	CAIR Nameplate Capacity (MWel) 89 MW
		NAICS Code	221119				
Unit ID#	Unit Type	08/01/1990		Check One: Actual <input checked="" type="checkbox"/> Projected ~			
Date unit began (or will begin) serving any generator producing electricity for sale (mm/dd/yyyy):							
Company Name: Hopewell Cogeneration Facility					~ Owner		
					<input checked="" type="checkbox"/> Operator		
Company Name: Suez Energy Generation NA					<input checked="" type="checkbox"/> Owner		
					~ Operator		
Company Name:					~ Owner		
					~ Operator		
Company Name:					~ Owner		
					~ Operator		
Company Name:					~ Owner		
					~ Operator		

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 3

STEP 5: Read the certifications, sign and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in ~~2~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and

Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source (i.e., the source and each unit subject to the CAIR NO_x Annual Trading Program, as indicated in ~~2~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Annual Trading Program on behalf of the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x unit, or where a utility or industrial customer purchases power from a CAIR NO_x unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x source and each CAIR NO_x unit at the source; and

CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x allowances by contract, CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 4

Clean Air Interstate Rule (CAIR) SO₂ Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source (i.e., the source and each unit subject to the SO₂ Trading Program, as indicated in ~~A~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO₂ Trading Program, on behalf of the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO₂ unit, or where a utility or industrial customer purchases power from a CAIR SO₂ unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO₂ source and each CAIR SO₂ unit at the source; and

CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO₂ allowances by contract, CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_x Ozone Season Trading Program, as indicated in ~~A~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Ozone Season Trading Program on behalf of the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_x Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit; and

CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x Ozone Season allowances by contract, CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source Name from Step 1)

Certificate of Representation - Page 5

COPY

General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (Designated Representative)	Date 16 May 2007
Signature (Alternate Designated Representative)	Date 13 June 2007



Certificate of Representation

Page 1

For more information, see instructions and 40 CFR 72.24, 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR); NO_x Annual, SO₂, and NO_x Ozone Season Trading Programs, or 40 CFR 97.113, 97.213, or 97.313, as applicable.

This submission is: ☐ New ☒ Revised (revised submissions must be complete; see instructions.)

FACILITY (SOURCE) INFORMATION

STEP 1
Provide
information for
the facility
(source).

Hopewell Cogeneration Facility Facility (Source) Name	Virginia State	10633 Plant Code
Independent City of Hopewell in the County of Prince George Virginia County Name		
N 37° 17' 30" Latitude	W 77° 16' 50" Longitude	

STEP 2
Enter requested
information for
the
designated
representative.

Robert L. Greene Name	Plant Manager Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>Bob.Greene@suezenergyna.com</u> E-mail address	

STEP 3
Enter requested
information for
the
alternate
designated
representative.

Chuck Barnes Name	Plant Engineer Title
Hopewell Cogeneration Facility Company Name	
1114 Hercules Road, Hopewell, Virginia 23860 Address	
(804) 458-0700 Phone Number	(804) 458-0794 Fax Number
<u>chuck.barnes@suezenergyna.com</u> E-mail address	

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s):	~ Acid Rain	~ CAIR NO _x Annual	~ CAIR SO ₂	X CAIR NO _x Ozone Season

ORIS-10633 DEQ-50967 ID# 1	CC Combined Cycle	Unit ID#	Unit Type	Source Category	Cogeneration	NAICS Code	221119	Generator ID Number	ID# 1	Acid Rain Nameplate Capacity (MW)e	CAIR Nameplate Capacity (MW)e
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):						Check One: Actual <input checked="" type="checkbox"/> Projected <input type="checkbox"/>					
Hopewell Cogeneration Facility											
Company Name:											
Suez Energy Generation NA											
Company Name:											
Company Name:											
Company Name:											
Company Name:											
Company Name:											

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NOx Annual ~ CAIR SO₂ ~ CAIR NOx Ozone Season

ORIS-10633 DEQ-50967 ID# 2	CC Combined Cycle	Source Category Cogeneration	Generator ID Number ID# 2	Acid Rain Nameplate Capacity (MW/a)	CAIR Nameplate Capacity (MW/a)
Unit ID#	Unit Type	NAICS Code 221119			89 MW
Date unit began (or will begin) serving any generator producing electricity for sale (mm/dd/yyyy):	08/01/1990				
Company Name:	Hopewell Cogeneration Facility			~ Owner X Operator	
Company Name:	Suez Energy Generation NA			X Owner ~ Operator	
Company Name:				~ Owner ~ Operator	
Company Name:				~ Owner ~ Operator	
Company Name:				~ Owner ~ Operator	
Company Name:				~ Owner ~ Operator	

COPY

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

UNIT INFORMATION

STEP 4: Complete one page for each unit located at the facility identified in STEP 1 (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine.) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NOx Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): ~ Acid Rain ~ CAIR NOx Annual ~ CAIR SO₂ X CAIR NOx Ozone Season

ORIS-10633 DEQ-50967 ID# 3	CC Combined Cycle	Source Category Cogeneration	Generator ID Number ID# 3	Acid Rain Nameplate Capacity (MW _e)	CAIR Nameplate Capacity (MW _e) 89 MW
Unit ID#	Unit Type	NAICS Code 221119			
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy):		Check One: Actual X Projected ~			
Hopewell Cogeneration Facility					
Company Name: ~ Owner X Operator					
Suez Energy Generation NA					
Company Name: X Owner ~ Operator					
Company Name: ~ Owner ~ Operator					
Company Name: ~ Owner ~ Operator					
Company Name: ~ Owner ~ Operator					

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 3

STEP 5: Read the certifications; sign and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in ~~the~~ Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and each affected unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the affected source and each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and

Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source (i.e., the source and each unit subject to the CAIR NO_x Annual Trading Program, as indicated in ~~the~~ Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Annual Trading Program on behalf of the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x unit, or where a utility or industrial customer purchases power from a CAIR NO_x unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x source and each CAIR NO_x unit at the source; and

CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x allowances by contract, CAIR NO_x allowances and proceeds of transactions involving CAIR NO_x allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 4

Clean Air Interstate Rule (CAIR) SO₂ Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source (i.e., the source and each unit subject to the SO₂ Trading Program, as indicated in ~~A~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO₂ Trading Program, on behalf of the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO₂ source and each CAIR SO₂ unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO₂ unit, or where a utility or industrial customer purchases power from a CAIR SO₂ unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO₂ source and each CAIR SO₂ unit at the source; and

CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO₂ allowances by contract, CAIR SO₂ allowances and proceeds of transactions involving CAIR SO₂ allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_x Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_x Ozone Season Trading Program, as indicated in ~~A~~Applicable Program(s) in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR NO_x Ozone Season Trading Program on behalf of the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_x Ozone Season unit, or where a utility or industrial customer purchases power from a CAIR NO_x Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit; and

CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_x Ozone Season allowances by contract, CAIR NO_x Ozone Season allowances and proceeds of transactions involving CAIR NO_x Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Hopewell Cogeneration Facility

Facility (Source) Name (from Step 1)

Certificate of Representation - Page 5

COPY

General

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Signature (Designated Representative)	Date 16 May 2007
Signature (Alternate Designated Representative)	Date 13 June 2007